DATA REQUEST

KPSC PHDR_1	Refer to Kentucky Power's response to Intervenor Comments on the 2022 Integrated Resource Plan (IRP), page. 4. Explain what contract the response "contract-based membership in PJM Interconnection, LLC (PJM)[]" is referencing. Provide a copy of the contract.

RESPONSE

The contracts referenced in the quoted statement are the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement among Load Serving Entities in the PJM Region, and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. Copies of the referenced contracts are publicly available on PJM's website and are attached as KPCO_R_KPSC_PHDR_1_Attachment1 through KPCO_R_KPSC_PHDR_1_Attachment3.

Witness: Brian K. West

CONSOLIDATED TRANSMISSION OWNERS AGREEMENT

RATE SCHEDULE FERC No. 42

CONSOLIDATED TRANSMISSION OWNERS AGREEMENT

This CONSOLIDATED TRANSMISSION OWNERS AGREEMENT ("Agreement") dated as of the 15th day of December 2005, is made by and among the Transmission Owners (hereinafter referred to collectively as "Parties" and individually as a "Party"). In addition, this Agreement is made by and between the Parties and PJM Interconnection, L.L.C. (hereinafter referred to as "PJM") solely for the purpose of establishing the rights and commitments of PJM identified herein.

WITNESSETH:

WHEREAS, on the date of initial execution of this Agreement, all then existing Parties had, pursuant to three separate Transmission Owner(s) agreements, previously agreed to transfer functional control of their Transmission Facilities to PJM;

WHEREAS, the Parties, acting pursuant to the three separate Transmission Owner(s) agreements, have agreed to consolidate the three separate Transmission Owner(s) agreements into this Agreement for the purposes established herein; and

WHEREAS, PJM's rights and commitments provided herein are in consideration of the Parties' commitments to PJM as set forth herein.

NOW THEREFORE, in consideration of the foregoing and the mutual covenants and promises made herein, the Parties and PJM agree as follows:

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles or Sections are to Articles or Sections of this Agreement. As used in this Agreement:

1.1 Administrative Committee

Administrative Committee shall mean that committee, consisting of representatives of each Party to this Agreement, established pursuant to Article 8 of this Agreement.

1.2 Affiliate or Affiliation

Affiliate or Affiliation shall mean any two or more entities, one of which Controls the other or that are under common Control.

1.3 Agreement

Agreement shall mean this Amended and Restated Transmission Owners Agreement, as it may be amended from time to time.

1.4 Applicable Regional Reliability Council

Applicable Regional Reliability Council shall mean the reliability council under Section 202 of the Federal Power Act, the rules and procedures of which, pursuant to written agreement, each Party has agreed to be bound, or the regional entity under Section 215(e)(4) of the Federal Power Act, the rules and procedures of which, pursuant to an order of the FERC, a Party is required to follow.

1.4A Attachment H

Attachment H shall refer collectively to the Attachments to the PJM Tariff with the prefix “H-“ that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

1.5 Control

Control shall mean the possession, directly or indirectly, of the power to direct the management or policies of any entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or Affiliation for purposes of this Agreement if: (i) the securities are held as an investment, (ii) the holder owns (in its name or via intermediaries) less than ten (10) percent of the outstanding securities or the entity, (iii) the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and (iv) the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Administrative Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten (10) percent or more of the voting securities of such entity.

1.6 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to: (i) match, at all times, the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s); (ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice: (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and the Applicable Regional Reliability Council of NERC; (iv) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and (v) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Effective Date

Effective Date shall mean such date that FERC permits this Agreement to go into effect.

1.8 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region.

1.9 FERC

FERC shall mean the Federal Energy Regulatory Commission, or any successor federal agency or commission exercising jurisdiction over this Agreement.

1.10 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

1.11 Individual Vote

Individual Vote shall mean the single vote accorded to each Party that is not in default and is otherwise authorized to vote in accordance with the terms of this Agreement; provided, however, that Parties that are Affiliates shall have a single Individual Vote; and further provided, however, that two or more Parties that are not Affiliates shall have a single Individual Vote if neither such Party owns Transmission Facilities subject to this Agreement other than Transmission Facilities which such Parties own jointly.

1.12 Interconnection Customer

Interconnection Customer shall have the meaning defined in the PJM Tariff.

1.13 Joint Transmission Rate

Joint Transmission Rate shall mean a transmission rate that applies to: (i) all Transmission Zones collectively; (ii) transactions that enter or exit the PJM Region; or (iii) one or more Transmission Zones other than the Zone(s) of the Transmission Owner(s) filing such rate.

1.14 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto, including the Electric Reliability Organization certified by FERC pursuant to Section 215(c) of the Federal Power Act.

1.14A Neutral Party

Neutral Party shall have the meaning defined in the PJM Tariff.

1.15 Open Access Same-Time Information System (OASIS)

Open Access Same-Time Information System (OASIS) shall have the meaning defined in the PJM Tariff.

1.16 Operating Agreement

Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997, and as amended from time to time thereafter, among the members of PJM.

1.17 PJM Region

PJM Region shall have the meaning defined in the PJM Tariff.

1.18 PJM Regional Rate Design

PJM Regional Rate Design shall mean a Rate Design that applies, in accordance with its terms, to all Zones in the PJM Region.

1.19 PJM Manuals

PJM Manuals shall have the meaning defined in the PJM Tariff.

1.20 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.21 Rate Design

Rate Design shall mean the design of the rates to recover a Transmission Owner's revenue requirement with respect to its Transmission Facilities or other amounts as authorized by FERC, including without limitation applicable incentives and a reasonable return.

1.22 Regional Transmission Expansion Plan

Regional Transmission Expansion Plan shall have the meaning defined in the PJM Tariff.

1.23 Regional Transmission Expansion Planning Protocol

Regional Transmission Expansion Planning Protocol shall mean Schedule 6 of the Operating Agreement, or any successor thereto.

1.24 Required Transmission Enhancements

Required Transmission Enhancements shall have the meaning defined in the PJM Tariff.

1.25 Regional Transmission Organization (RTO)

Regional Transmission Organization (RTO) shall mean an organization in effect during the term of this Agreement and approved by FERC as an RTO.

1.26 Transmission Customer

Transmission Customer shall have the meaning defined in the PJM Tariff.

1.27 Transmission Facilities

Transmission Facilities shall mean those facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of PJM to be integrated with the Transmission System of the PJM Region and integrated into the planning and operation of such to serve the power and transmission customers within such region, regardless of whether the facilities are listed in the PJM Designated Facilities List contained in the PJM Manual of Transmission Operations or successor thereto.

1.28 Transmission Owners

Transmission Owners shall mean those entities that own or lease (with rights equivalent to ownership) Transmission Facilities. For purposes of this Agreement only, a Transmission Owner who is a generation and transmission cooperative (in addition to being the Transmission Owner for its own Transmission Facilities) shall also be the Transmission Owner for the Transmission Facilities of its cooperative members, with all rights and obligations specified under this agreement with regard to such Transmission Facilities, provided, however, that (a) it has been affirmatively granted in writing binding authority by such cooperative members to assume such rights and obligations, (b) that it affirmatively represents and warrants in writing to the other Parties and PJM that it has authority to act for and on behalf of such members, and (c) that any such cooperative member shall not be a Transmission Owner. The Transmission Owners are listed in Attachment A.

1.29 Transmission Planned Outage

Transmission Planned Outage shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in the Operating Agreement or the PJM Manuals.

1.30 Transmission System

Transmission System shall have the meaning given in the PJM Tariff.

1.31 Weighted Votes

Weighted Votes shall mean the number of votes accorded to each Party, which shall be equal to the net book value, as determined in accordance with FERC's Uniform System of Accounts, of each Party's Transmission Facilities (expressed in dollars and divided by one million (1,000,000)), as determined on April 1 of each year on the basis of the net book value as of the prior December 31; provided, however, the Weighted Votes of all Parties shall be adjusted in a proportional manner as agreed to by the Administrative Committee so that no Party (together with its Affiliates) shall have more than twenty-four and nine-tenths percent (24.9%) of the sum of the Weighted Votes. The net book value of each Party's Transmission Facilities shall be determined based on current data filed with FERC in Form No. 1 or 1F or any successor thereto, unless a Party does not file a Form 1 or 1F in which case, the net book value of a Party's Transmission Facilities shall be determined based on a certification from the Party's independent auditor submitted to the Administrative Committee by April 1 of each year under oath by an officer of such Party without any claim of confidentiality. Such certification shall state specific values for electric transmission plant in service, accumulated depreciation, and the net book value of Transmission Facilities.

1.32 Zero Revenue Requirement Party

Zero Revenue Requirement Party means a Party that is a Transmission Owner solely by virtue of Transmission Facilities used to provide transmission services within the PJM Region under the PJM Tariff for which it does not have a cost-of-service rate for such services set forth in Schedules 7 and 8 and Attachment H of the PJM Tariff.

1.33 Zone

Zone shall have the meaning defined in the PJM Tariff.

ARTICLE 2 – PURPOSES AND OBJECTIVES OF THIS AGREEMENT

The Parties have entered into this Agreement to: (i) facilitate the coordination of planning and operation of their respective Transmission Facilities within the PJM Region; (ii) transfer certain planning and operating responsibilities to PJM; (iii) provide for regional transmission service pursuant to the PJM Tariff and subject to administration by PJM; and (iv) establish certain rights and obligations that will apply to the Parties and PJM.

ARTICLE 3 – PARTICIPATION IN THIS AGREEMENT

3.1 Parties.

It is the intent of the Parties and PJM that this Agreement serve as the sole Transmission Owners Agreement for all Transmission Facilities in PJM. Further, it is the agreement of the Parties and PJM that any entity that: (i) owns, or, in the case of leased facilities, has rights equivalent to ownership in, Transmission Facilities; (ii) has in place all equipment and facilities necessary for safe and reliable operation of such Transmission Facilities as part of the PJM Region; and (iii) has committed to transfer functional control of its Transmission Facilities to PJM shall become a Party to this Agreement. Any disputes regarding whether an entity has satisfied the requirements for becoming a Party in this Section 3.1 shall be resolved by PJM, subject to the dispute resolution procedures set out in the Operating Agreement.

Prior to this Agreement becoming effective as to any such entity, each of the following events shall have occurred:

i. The Operating Agreement is in full force and effect.
ii. The Operating Agreement has been executed by the entity.
iii. This Agreement has been executed by the entity.
iv. All required regulatory approvals have been obtained.

3.2 Withdrawal From This Agreement.

Any Party may withdraw from this Agreement upon ninety (90) days advance written notice to PJM and the other Parties; provided that such withdrawal shall not be effective until the withdrawing Party has: (i) if its Transmission Facilities do not comprise an entire Control Area, satisfied all applicable standards of NERC and the Applicable Regional Reliability Council for operating a Control Area or being included within an existing Control Area; (ii) put in place alternative arrangements for satisfaction of the FERC's requirements with respect to comparable transmission services; and (iii) made a filing with the FERC under Section 205 of the Federal Power Act to withdraw from this Agreement, and such filing has been approved, accepted without suspension, or if suspended, the suspension period has expired before the FERC has issued an order on the merits of the filing. Notwithstanding the forgoing, a Zero Revenue Requirement Party may withdraw from this Agreement in the particular circumstance of permanent removal of its owned Transmission Facilities from service, provided that such Party has: (a) provided written notice to PJM and the parties to the Operating Agreement at least twelve months in advance of the intended date of retirement of its owned Transmission Facilities, and (b) complied with all reasonable requirements of PJM for restoration, to the maximum extent reasonably attainable, of the PJM Transmission System to the same configuration and operational capability that existed prior to such Party's installation of its owned Transmission Facilities.

3.3 Transfers or Assignments.

A Party that transfers or assigns its ownership of, or its rights equivalent to ownership in, Transmission Facilities shall require the transferee or assignee to assume all rights and obligations under this Agreement and to become a Party to this Agreement.

3.4 Obligations After Withdrawal, Transfer, or Assignment.

Any Party that withdraws from, transfers, or assigns this Agreement in accordance with Sections 3.2 or 3.3 hereof, shall remain liable for any and all obligations under this Agreement that such Party incurred, that were incurred on behalf such Party, or that arose hereunder prior to the date upon which such Party's withdrawal, transfer, or assignment became effective. Withdrawal from, transfer, or assignment of this Agreement shall not relieve such Party of any of its indemnification or liability obligations pursuant to Article 9 hereof for any events occurring prior to the time that its withdrawal from this Agreement became effective.

3.5 Cessation of Effectiveness.

Subject to provisions of this Agreement providing for survival and Section 3.4, this Agreement shall cease to be effective with respect to any function PJM provides under, or in connection with, this Agreement in the event that PJM ceases to be approved by the FERC to provide such function as an RTO or in the event that all Transmission Owners have withdrawn from this Agreement under Section 3.2.

ARTICLE 4 – PARTIES' COMMITMENTS

Each Party agrees to the following commitments and undertakings:

4.1 Rights and Responsibilities Transferred to PJM.

4.1.1 Transmission Service.

Each party shall authorize PJM to provide transmission service over its Transmission Facilities in the PJM Region under the PJM Tariff.

4.1.2 Directing the Operation of Transmission Facilities.

Each Party shall transfer to PJM, pursuant to this Agreement and in accordance with the Operating Agreement, the responsibility to direct the operation of its Transmission Facilities provided that such transfer is not intended to require any change in the physical operations or control over Transmission Facilities.

4.1.3 PJM Tariff.

Each Party shall transfer to PJM, pursuant to this Agreement and in accordance with the Operating Agreement, responsibility for administering the PJM Tariff.

4.1.4 Planning Information.

Each party shall transfer to PJM, pursuant to this Agreement and in accordance with the Operating Agreement, the responsibility to prepare a Regional Transmission Expansion Plan and to provide information reasonably requested by PJM to prepare the Regional Transmission Expansion Plan and shall otherwise cooperate with PJM in such preparation.

4.1.5 Operations Support.

As required by the PJM Tariff, the Operating Agreement, the PJM Manuals, or as otherwise reasonably requested by PJM, each Party will provide to PJM necessary data, information and related technical support consistent with enabling PJM to monitor and analyze system conditions so that PJM may affirmatively determine that PJM is in compliance with NERC standards.

4.2 Obligation to Build.

4.2.1

Subject to: (i) the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits; (ii) the availability of required financing; (iii) the ability to acquire necessary right-of-way; (iv) the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment; and (v) other conditions or exceptions set forth in the Regional Transmission Expansion Planning Protocol, Parties designated as the appropriate entities to construct and own or finance enhancements or expansions applicable to the PJM Region specified in the Regional Transmission Expansion Plan or required to expand or modify Transmission Facilities pursuant to the PJM Tariff shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations.

4.2.2 Acknowledgement of Construction Designation.

Within ninety (90) days of receiving notification from PJM pursuant to Section 1.6 of the Regional Transmission Expansion Planning Protocol, that the PJM Board has approved a Regional Transmission Expansion Plan designating a Party to construct and own or finance specified enhancements or expansions applicable to the PJM Region, such Party shall provide to PJM and the Administrative Committee: (1) an acknowledgement of such designation or the reasons why the Party disagrees with such designation or any aspect thereof, and (2) a proposed preliminary schedule for such enhancements or expansions.

4.2.3

A Zero Revenue Requirement Party shall not be required to participate in the construction and ownership or financing of enhancements or expansions described in Section 4.2.1 except to the extent that such enhancements or expansions involve the expansion or modification of that Party's Transmission Facilities. A Zero Revenue Requirement Party shall construct and own or finance all expansions and modifications of its own Transmission Facilities or enter into appropriate contracts to fulfill such obligation, and no other Party shall be required to participate in the construction and ownership or financing of such expansion or modification. A Zero Revenue Requirement Party shall continue to be reimbursed by an individual Interconnection Customer directly or indirectly for costs of expansion and modification the responsibility for which was directly assigned to that Interconnection Customer pursuant to the PJM Tariff, and such Zero Revenue Requirement Party shall be obligated to provide the Interconnection Customer whatever credits the Interconnection Customer may be entitled to receive under the PJM Tariff in return for such reimbursement.

4.3 Interconnection and Transmission Customers.

Unless otherwise specified in agreements, or tariffs on file at FERC and in effect, each Party shall install and construct Transmission Facilities required for interconnection of an Interconnection Customer or Transmission Customer in accordance with the PJM Tariff.

4.4 Permanently Taking Facilities Out of Service.

Prior to permanently taking out of service any of its Transmission Facilities within the PJM Region, the Party owning such Transmission Facilities shall provide PJM with reasonable advance notice.

4.5 Operation and Maintenance.

Each Party shall operate and maintain its Transmission Facilities in accordance with: (i) the terms of this Agreement; (ii) applicable reliability principles, guidelines, and standards of the Applicable Regional Reliability Council and NERC; (iii) the PJM Manuals; (iv) the direction of PJM consistent with this Agreement; and (v) Good Utility Practice. Consistent with the provisions of this Section 4.5, the Parties shall conform to PJM's operating instructions as they apply to such Party's Transmission Facilities. The Parties will continue to direct the operation and maintenance of Transmission Facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations or any successor thereto and each Party will physically operate and maintain all Transmission facilities that it owns.

4.6 Interconnection Facilities.

Interconnections between the Parties' electric systems and between a Party's system and systems of entities not a Party to this Agreement shall be kept in place and shall be maintained in good operating condition in accordance with Good Utility Practice and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC unless the interconnected parties determine, in accordance with Good Utility Practice and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC, that any such interconnection should be modified or abandoned; provided, however, that nothing herein shall prohibit any Party from disconnecting its electrical systems from the facilities of any other entity, if such Party reasonably determines that disconnection is required for safety or reliability reasons.

4.7 Actions in Emergency.

Each Party shall follow PJM’s operating instructions during an emergency; provided, however, that a Party may at any time take or decline to take any action(s) that it deems necessary to prevent injury to persons or loss of human life or prevent damage to property.

4.8 Maintenance Schedules.

The Parties shall coordinate with other Parties and with the owners of generation facilities within the PJM Region the maintenance of their Transmission Facilities, and the scheduling of a Transmission Planned Outage, taking into account transmission and generation outage schedules established by PJM and the PJM Manuals, and in accordance with the following planned outage scheduling procedures:

4.8.1

Each Party shall use reasonable efforts to submit Transmission Planned Outage schedules one year in advance but by no later than the first of the month six months in advance of the requested start date for all outages that are expected to exceed five (5) working days duration, with regular (at least monthly) updates as new information becomes available.

4.8.2

If notice of a Transmission Planned Outage is not provided in accordance with the requirements in Section 4.8.1 above, and if such outage is determined by PJM to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the PJM may require the Party to implement an alternative outage schedule to reduce or avoid such impacts. PJM may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under this Agreement, the PJM Operating Agreement or PJM Tariff and provided PJM determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had PJM implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. PJM may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from PJM's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in this Agreement, the PJM Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

4.8.3

Each Party shall submit notice of all Transmission Planned Outage to PJM by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.

4.8.4

If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by PJM to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then PJM may require the Party to implement an alternative outage schedule to reduce or avoid such impacts. PJM shall perform this analysis and notify the affected Party in a timely manner if it will require rescheduling of the outage. PJM may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under this Agreement, the PJM Operating Agreement or PJM Tariff and provided PJM determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had PJM implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. PJM may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from PJM's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in this Agreement, the PJM Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

4.8.5

PJM reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure reliable system operations on a case by case basis regardless of duration or date of submission.

4.8.6

PJM shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the affected Party; provided, however, that PJM shall not post on OASIS notice of any component of such outage to the extent such component shall directly reveal a generator outage. In such cases, the affected Party, in addition to providing notice to PJM as required above, concurrently shall inform the affected generation owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the generation owner on matters of safety to persons, facilities, and equipment. The affected Party shall not notify any other market participant of such outage and shall arrange any other necessary coordination through PJM. If PJM determines that transmission maintenance schedules proposed by one or more Parties would significantly affect the efficient and reliable operation of the PJM Region, PJM may establish alternative schedules, but such alternative schedules shall minimize the economic impact on the Party or Parties whose maintenance schedules PJM proposes to modify. Except as otherwise provided in this Agreement, the Parties shall comply with all maintenance schedules established by PJM.

4.9 Data, Information and Metering.

The Parties shall comply with the data, information and metering requirements established by PJM, as reflected in the PJM Manuals including but not limited to posting notices as required by Section 4.8.

4.10 Connections with Non-Parties.

No Party shall permit its Transmission Facilities or distribution facilities to be connected with the facilities of any entity which is not a Party without an interconnection agreement that contains provisions for the safe and reliable operation of each interconnection in accordance with Good Utility Practice, and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC or comparable requirements of an applicable retail tariff or agreement approved by appropriate regulatory authority. Subject to applicable regulatory requirements, any dispute regarding the adequacy of such agreements shall be resolved by PJM, subject to the dispute resolution provisions of the Operating Agreement.

4.11 Transmission Facility Ratings.

All Parties shall regularly update and verify Transmission Facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals:

4.11.1

Each Party shall verify to the Operations Planning Department (or successor Department) of PJM all of its Transmission Facility ratings two months prior to the beginning of the summer season (i.e., on April 1) and two months prior to the beginning of the winter season (i.e., on October 1) each calendar year, and shall provide detailed data justifying such transmission facility ratings when directed by PJM.

4.11.2

In addition to the seasonal verification of all ratings, each Party shall submit to the Operations Planning Department (or successor Department) of PJM updates to its Transmission Facility ratings as soon as such Party is aware of any changes. Such Party shall provide PJM with detailed data justifying all such Transmission Facility ratings changes.

4.11.3

All Parties shall submit to the Operations Planning Department (or successor Department) of PJM formal documentation of any criteria for changing Transmission Facility ratings under specific conditions, including: the detailed conditions under which such procedures will apply, detailed explanations of such criteria, and detailed calculations justifying such pre-established changes to facility ratings. Such criteria must be updated twice each year consistent with the provisions of this section.

4.11.4

PJM shall maintain a database of all Transmission Facility ratings, and shall review, and may modify or reject, any submitted change to such ratings or any submitted procedure for pre-established changes to such ratings. PJM shall provide notice no later than thirty (30) days after receiving a request for a proposed rating change of the acceptance, denial, or deferral of such change, including a written explanation of the basis for denying or deferring such change if the change is denied or deferred. Any dispute between a Party and PJM concerning Transmission Facility ratings shall be resolved in accordance with Section 9.19 of this Agreement; provided, however, that the rating level determined by PJM shall govern and be effective during the pendency of any such dispute.

ARTICLE 5 – PARTIES' RETAINED RIGHTS

Notwithstanding any other provision of this Agreement, each Party shall retain all of the rights set forth in this Article 5; provided, however, that such rights shall be exercised in a manner consistent with a Party's obligations under the Federal Power Act and the FERC's rules and regulations thereunder.

5.1 Procedures.

Each Party shall have the right to adopt and implement procedures it deems necessary to protect its electric facilities from physical damage or to prevent injury or damage to persons or property.

5.2 Facility Rights.

Each Party shall have the right to build, finance, own, acquire, sell, dispose, retire, merge or otherwise transfer or convey all or any part of its assets, including any Transmission Facilities, such right to include, but not be limited to the right, individually or collectively, to terminate the relationship with PJM in accordance with Section 3.2 or in connection with the transfer to or creation of another entity (including a joint venture or an ITC pursuant to Attachment U to the PJM Tariff) of the right to own and/or operate its Transmission Facilities. PJM shall not challenge any such sale, disposition, retirement, merger, or other action under this Section 5.2 on the basis that they are a signatory to this Agreement.

5.3 Actions to Fulfill Obligations.

Each Party shall have the right to take whatever actions it deems necessary to fulfill its obligations under local, state or federal law.

5.4 Federal Power Act Rights.

Except as otherwise provided in this Agreement, each Party retains its rights pursuant to the Federal Power Act and the FERC's rules and regulations thereunder.

5.5 Enforcement of Obligations.

Each Party shall have the right to seek enforcement of the obligations of any Party or of PJM under this Agreement subject to the terms and conditions of the Operating Agreement and the PJM Tariff.

5.6 Reservation of Rights.

Rights not specifically transferred by the Parties to PJM pursuant to this Agreement or any other agreement are expressly reserved by the Parties.

ARTICLE 6 – PJM's RIGHTS AND COMMITMENTS

6.1 Condition to Acceptance of Functional Control.

PJM shall condition the transfer of functional control over an entity's Transmission Facilities to PJM on such entity becoming a Party to this Agreement.

6.2 Rights of PJM under this Agreement.

PJM shall have the right to seek enforcement of the obligations of any Party to PJM under Article 6 of this Agreement.

6.3 Obligations of PJM under this Agreement.

PJM shall:

6.3.1

Direct the operation and coordinate the maintenance of the Transmission Facilities of the Parties in accordance with: (i) the Operating Agreement; (ii) the PJM Tariff; (iii) Good Utility Practice; and (iv) NERC and Applicable Regional Reliability Council operation and planning standards, principles and guidelines.

6.3.2

Administer the PJM Tariff and provide service thereunder in the PJM Region.

6.3.3

Administer the Regional Transmission Expansion Planning Protocol and provide related timely reports to the Administrative Committee consistent with the Operating Agreement and the PJM Tariff.

6.3.4

Conduct its planning for the expansion and enhancement of transmission facilities based on a planning horizon of at least ten years, or such longer period as may be required by the PJM Tariff or Operating Agreement, including the Regional Transmission Expansion Planning Protocol.

6.3.5

Maintain its status as an RTO.

6.3.6

Collect and pay to each Party all amounts due to such Party as a Transmission Owner under the PJM Tariff and to distribute such amounts in accordance with the PJM Tariff and this Agreement.

6.3.7

Work cooperatively with Transmission Owner(s) desiring to create a new or reformed transmission-owning entity in accordance with Section 5.2 and other applicable provisions of this Agreement.

6.3.8

Participate in scheduled meetings of the Administrative Committee and furnish appropriate information and reports to keep the Parties regularly informed as to matters arising under this Agreement.

6.3.9

Consult with committees jointly established by the Parties and PJM with respect to matters arising under this Agreement.

ARTICLE 7 – CHANGES TO RATE DESIGN AND TARIFF TERMS AND CONDITIONS; DISTRIBUTION OF REVENUES

7.1 Individual Transmission Owner Rates.

Notwithstanding any other provision of this Agreement, each Party expressly and individually reserves unto itself the following rights:

7.1.1

Each Party shall have the exclusive right to file unilaterally at any time pursuant to Section 205 of the Federal Power Act to establish or change the transmission revenue requirement for services provided under the PJM Tariff with respect to its Transmission Facilities (regardless of whether such revenue requirement is used to support rates and charges for delivery within its Zone or outside its Zone). This right includes, but is not limited to, the right to file a transmission revenue requirement, or a revenue requirement that is based on incentive or performance-based factors.

7.1.2 [Reserved for Future Use]

7.1.3

Each Party shall have the exclusive right to file unilaterally, at any time pursuant to Section 205 of the Federal Power Act, to change rates and charges for transmission and ancillary services (including, without limitation, incentive rates, and rates and charges for new services) for delivery within its Zone, which rates and charges are based solely on the costs of the Transmission Facilities of such Party.

7.1.4

A filing that is otherwise consistent with this Section 7.1 which changes the rate applicable within a Zone and which also applies to transactions that enter that Zone from outside the PJM Region shall not require approval under Section 8.5.1.

7.2 PJM Regional Rate Design and Joint Transmission Rates.

7.2.1

Section 205 filings to change the PJM Regional Rate Design or file for Joint Transmission Rates may only be made by the Parties, acting collectively, pursuant to a filing approved in accordance with Section 8.5.1 of this Agreement. The Parties, acting individually, shall have no authority to make any filings under Section 205 of the Federal Power Act either to change or which would be inconsistent with the PJM Regional Rate Design or Joint Transmission Rates.

7.2.2

Nothing in this Agreement is intended to authorize the PJM Transmission Owners to file pursuant to Section 205 of the Federal Power Act, as part of a filing to change the PJM Regional Rate Design, Joint Transmission Rates, or otherwise, proposed changes to those rates and charges for which an individual Party has reserved filing rights under Section 7.1 without the express consent of such Party, unless such change is required to be consistent with a Joint Transmission Rate or PJM Regional Rate Design adopted pursuant to Sections 7.2.1 and 7.3.

7.3 Filing of Transmission Rates and Rate Design Under Section 205.

7.3.1

The Transmission Owners shall have the exclusive and unilateral rights to file pursuant to Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder for any changes in or relating to the establishment and recovery of the Transmission Owners' transmission revenue requirements or the PJM Regional Rate Design, and such filing rights shall also encompass any provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by the Transmission Owners. Nothing herein is intended to limit or change the right of individual Transmission Owners as specified under Sections 7.1 and 7.3. Except as provided in Section 7.1.1, the Transmission Owners may only file under Section 205 to change the PJM Regional Rate Design pursuant to a filing approved in accordance with Section 8.5.1.

7.3.2

If the Transmission Owners agree upon a change referred to in Section 7.2.1 by vote in accordance with Section 8.5.1, the Transmission Owners shall make such filing jointly pursuant to Section 205 of the Federal Power Act. For purposes of administrative convenience, at the request of the Transmission Owners, PJM may, but shall not be required to, make the Section 205 filings with the FERC on behalf of the Transmission Owners; provided that any such filing by PJM shall be deemed for all purposes under the Federal Power Act to be a filing of the Transmission Owners. The Transmission Owners shall consult with PJM and the PJM Members Committee beginning no less than thirty (30) days prior to any Section 205 filing hereunder, but neither PJM (except as provided for in Section 7.6) nor the PJM Members Committee shall have any rights to veto or delay the Transmission Owners' Section 205 filing hereunder; provided that the Transmission Owners may file with less than a full 30 day advance consultation in circumstances where imminent harm to system reliability or imminent severe economic harm to electric consumers requires a prompt Section 205 filing; provided further that the Transmission Owners shall provide as much advance notice and consultation with PJM and the PJM Members Committee as is practicable in such circumstances and no such filing shall be made with less than 24 hours' advance notice.

7.3.3

Nothing in this Section 7.3 is intended to limit the rights of any Party or other person to oppose such a Section 205 filing pursuant to Section 206 or any other applicable provision of the Federal Power Act, or to limit the right of any Party or other person to make filings under Section 206 of the Federal Power Act.

7.3.4

The following provisions of the PJM Tariff and any successors thereto shall be within the Transmission Owners' exclusive and unilateral rights to make Section 205 filings: (i) Section 34; (ii) Schedule 1A; (iii) Schedule 7 (except as to transmission congestion charges under Attachment K to the PJM Tariff or any successor thereto); (iv) Schedule 8 (except as to transmission congestion charges under Attachment K to the PJM Tariff or any successor thereto); (v) Schedule 11; (vi) Schedule 12; (vii) Attachment H-A; (viii) Attachment J; and (ix) Attachment R; provided, however, that if a filing pursuant to Section 205 is required to effect a change in any of the forgoing provisions of the PJM Tariff, solely by reason of a filing by an individual PJM Transmission Owner pursuant to Section 7.3.5, PJM may make such a filing if: (a) five business days prior to making such filing, PJM provides the PJM Transmission Owners with each proposed change including an explanation thereof; and (b) no PJM Transmission Owner notifies PJM that it objects to PJM making such filing.

7.3.5

Consistent with Section 7.3.1, the following provisions of the PJM Tariff and any successors thereto shall be within the exclusive and unilateral rights to make Section 205 filings of the individual Transmission Owner to which the provisions apply: (i) Attachment H (other than Attachment H-A) (except as to transmission congestion charges under Attachment K to the PJM Tariff or any successor thereto); (ii) Attachment M-1 (First Energy); (iii) Attachment M-2 (First Energy); (iv) Procedures for Load Determination (PSE&G); (v) Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers (Atlantic City); and (vi) Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers (Delmarva).

7.3.6

The listing of provisions in Sections 7.3.4 and 7.3.5 above is not exclusive, and failure to specify a provision of the PJM Tariff in this Section 7.3 shall not be deemed to be an admission or agreement by the Transmission Owners that such provision or any change thereto does not relate to the establishment and recovery of the Transmission Owners' transmission revenue requirements or the PJM Regional Rate Design or Joint Transmission Rates, or encompass any provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by the Transmission Owners. The Transmission Owners reserve their rights to assert that other provisions of the PJM OATT should be included within their Section 205 rights, and PJM reserves its rights to contest such assertions.

7.3.7

The Transmission Owners' Section 205 rights shall include the unilateral right to file for incentive and performance based rates that affect or relate to transmission revenue requirements, transmission rate design, or any performance or incentive rates in which the incentives to the Transmission Owners may be measured by savings or efficiencies in the power or ancillary services markets resulting from the construction, operation or maintenance of Transmission Facilities. Nothing in this Agreement is intended to limit PJM's right to make Section 205 filings to establish incentive or performance based rates applicable to market participants, provided that PJM must obtain the prior approval of the Transmission Owners (pursuant to Section 8.5.1 of this Agreement) for any portion of such a filing that reasonably could be expected to affect the establishment and recovery of the Transmission Owners' transmission revenue requirements, transmission rate design or the recovery of transmission-related costs by the Transmission Owners.

7.4 Transmission Rate Zone Size.

For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement.

7.5 Changes in Terms and Conditions.

The Parties may propose to revise any of the non-rate terms and conditions of the PJM Tariff in a manner consistent with requirements of FERC. Any such proposal shall be submitted to PJM for action pursuant to the Operating Agreement.

7.5.1 Filing of Changes in Terms and Conditions Under Section 205.

(i) PJM shall have the exclusive and unilateral rights to file pursuant to Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder to make changes in or relating to the terms and conditions of the PJM Tariff (including but not limited to provisions relating to creditworthiness, billing, and defaults) as well as all charges for recovery of PJM costs. PJM shall not have any Section 205 filing rights with respect to the subject matters described in Sections 7.1 and 7.2 of this Agreement. PJM shall not have any Section 205 filing rights with respect to the provisions of the PJM Tariff listed in Sections 7.3.4 and 7.3.5 of this Agreement.

(ii) PJM shall consult with the Transmission Owners and the PJM Members Committee beginning not less than seven (7) days in advance of any such Section 205 filing, but neither the Transmission Owners (except as provided for in Section 7.6) nor the PJM Members Committee shall have any right to veto or delay any such Section 205 filing. PJM may file with less than a full seven (7) day advance consultation in circumstances where imminent harm to system reliability or imminent severe economic harm to electric consumers requires a prompt Section 205 filing; provided that PJM shall provide as much advance notice and consultation with the Transmission Owners and the PJM Members Committee as is practicable in such circumstances, and no such emergency filing shall be made with less than 24 hours advance notice.

(iii) Nothing herein is intended to limit the rights of any Party or other person to oppose such a Section 205 filing pursuant to Section 206 or any other applicable provision of the Federal Power Act or to limit the right of any Party or other person to make filings under Section 206 of the Federal Power Act.

(iv) To the extent that PJM desires to add a provision to the PJM Tariff, or to change an existing provision thereof, in accordance with PJM's rights under Section 7.5.1 (i), the Transmission Owners shall have unilateral and exclusive rights to make Section 205 filings with respect to any matters covered by such new or changed provisions relating to the establishment and recovery of the Transmission Owners' transmission revenue requirements, the PJM Regional Rate Design or Joint Transmission Rates, or any provisions governing the recovery of transmission-related costs incurred by the Transmission Owners. Prior to making any Section 205 filing covered by Section 7.5.1 (i) that also relates to or affects the establishment and recovery of the Transmission Owners' transmission revenue requirements and the PJM Regional Rate Design or Joint Transmission Rates, or any provisions governing the recovery of transmission-related costs incurred by the Transmission Owners, PJM shall provide no less than 45 days notice to the Transmission Owners of the intended filing in sufficient detail to provide them a reasonable opportunity to include appropriate provisions in the PJM Tariff governing these subjects, either through a Section 205 filing by the Transmission Owners or approval by the Transmission Owners of the PJM proposal pursuant to Section 8.5.1.

7.5.2 Filing of Changes in Rate Design, Terms and Conditions Under Section 206.

Any Party or any group of Parties shall have the right to submit a proposal to the FERC to change the Rate Design and the non-rate terms and conditions of the PJM Tariff pursuant to Section 206 of the Federal Power Act. Nothing herein is intended to limit the rights of PJM, any Party, or other person to oppose proposed changes to the terms and conditions filed by PJM, a Party, or group of Parties.

7.6 Disputes Regarding Exclusive Filing Rights.

If at the time that a proposal to change or amend any part of the PJM Tariff, or to add any new provision, is submitted to PJM or the Transmission Owners for consultation pursuant to Sections 7.3.2 or 7.5.1 (ii), a dispute arises as to which Party has Section 205 rights to make such filing, the following procedures shall apply:

7.6.1

The Administrative Committee and PJM shall meet promptly prior to the filing in order to resolve the dispute. Such resolution may include a joint Section 205 filing by the Transmission Owners and PJM.

7.6.2

If the Transmission Owners propose to make the Section 205 filing, they shall defer such filing beyond the 30-day notice and consultation period provided for in Section 7.3.2 for up to 10 additional days at the request of PJM to allow the dispute to be resolved.

7.6.3

If PJM proposes to make the Section 205 filing, it shall defer any filing beyond the 7 day notice and consultation period provided for in Section 7.5.1 (ii) for up to 10 additional days to allow the dispute to be resolved;

7.6.4

In order to resolve a dispute, the agreement of the Transmission Owners must be obtained by vote in accordance with Section 8.5.1 of this Agreement;

7.6.5

If the Parties are unable to reach agreement among themselves, the matter shall be presented to and resolved by a Neutral Party chosen as follows and, except as provided in this Section 7.6.5, such resolution shall be binding on the Parties: The Chairman of the Administrative Committee (or his/her designee) and an executive of PJM chosen by the President shall choose the Neutral Party and shall have authority to enter into an agreement that will make the Neutral Party available on a prompt basis to resolve disputes hereunder. PJM and the Transmission Owners shall share in the cost of any Neutral Party on an equal basis. The Chairman of the Administrative Committee (or his/her designee) and an executive of PJM chosen by the President may replace the Neutral Party at any time they mutually deem such action to be appropriate or necessary. The decision of the Neutral Party as to which Parties have Section 205 rights hereunder shall be made within the period provided for consultation between the Transmission Owners and PJM as set forth in Sections 7.6.2 or 7.6.3, as applicable. Interested parties (including the Parties) may file a complaint seeking review by the FERC of the Neutral Party's decision, and the FERC's authority to interpret which Parties have Section 205 rights shall not be limited by the Neutral Party's decision as it relates to these disputes.

7.6.6

Nothing in this Section 7.6 is intended to limit the Parties' rights to make filings subject to this dispute resolution provision pursuant to Section 206 of the Federal Power Act prior to resolution of such dispute.

7.7 PJM Cooperation

Notwithstanding the allocation of filing rights under this Agreement, PJM shall cooperate with the filing of a revenue requirement or changes thereto of a Party not subject to the jurisdiction of FERC under Part II of the Federal Power Act.

7.8 Distribution of Revenues.

Transmission revenues received from network or firm point-to-point transmission service to load within the PJM Region will be distributed to the Transmission Owners on a revenue requirements basis to the Parties with transmission revenue requirements for the Zone in which the load is located; transmission revenues from other network or firm point-to-point transmission service will be distributed to all Parties to this Agreement on a transmission revenue requirements ratio share basis; and transmission revenues from non-firm point-to-point transmission service will be distributed in accordance with the PJM Tariff. Any other revenues owed to the Transmission Owners shall be distributed on a transmission revenue requirements ratio share basis unless otherwise specified in the PJM Tariff. The above notwithstanding, no revenues shall be distributed to any Party that is a Zero Revenue Requirement Party.

ARTICLE 8 – THE ADMINISTRATIVE COMMITTEE

8.1 Duties and Responsibilities.

The Administrative Committee shall have the authority to propose policies and recommendations to PJM as to any matters relating to the Parties' Transmission Facilities; provided, however, that PJM shall not be required to adopt such policies or recommendations and that the Administrative Committee shall not exercise any control over functions and responsibilities transferred to PJM pursuant to this Agreement, the PJM Tariff or the Operating Agreement. The Administrative Committee shall also have the authority to establish such committees, subcommittees, task forces, working groups or other bodies as it shall deem appropriate and the responsibility to undertake any other action delegated to it pursuant to this Agreement. The Administrative Committee shall determine the Affiliate status of Parties for purposes of Individual or Weighted Votes.

8.2 Representatives.

Each Party shall appoint one or more representatives and alternate representative(s) to serve as a member of the Administrative Committee with authority to act for that Party with respect to actions taken or decisions made by the Administrative Committee. The representative(s) shall be an officer or agent of the Party, having binding decision-making authority with respect to the transmission affairs of the Party. Each representative shall be a member of the Administrative Committee; provided, however, that each Party's alternate shall serve as a member of the Administrative Committee during any absence of that Party's representative.

8.2.1 Initial Representatives.

Unless a Party appoints a different representative and alternate, the representatives and alternates of the Parties appointed under the Transmission Owners agreements in effect on the day prior to the effective date of this Agreement shall be the initial representatives and alternates under this Agreement. Subsequent to the Effective Date of this Agreement, an entity that becomes a Party pursuant to Section 3.1 hereof shall appoint its representative(s) and alternate(s) and provide written notice to the other Parties within thirty (30) days after becoming a Party.

8.2.2 Change of or Substitution for a Representative or Alternate.

A Party may at any time upon providing written notice to the other Parties designate a replacement representative or alternate. Any member of the Administrative Committee, by providing written notice to the Chair of the Administrative Committee, may designate a substitute to act for him or her with respect to any matter specified in such written notice.

8.3 Officers.

At the initial meeting of the Administrative Committee, a Chair and Vice Chair shall be elected from among the Parties' representatives on the Administrative Committee. The term of office for the Chair and Vice Chair shall be one year, or until succession to each office occurs as provided herein. Except as provided in Section 8.3.1, at each annual meeting, the Vice Chair shall succeed to the office of the Chair, and a new Vice Chair shall be elected.

8.3.1 Vacancies.

If the office of the Chair becomes vacant for any reason, the Vice Chair shall succeed to the office of the Chair and a new Vice Chair shall be elected at the next regular or special meeting; provided that following such vacancy of the Chair, the succeeding Chair and Vice Chair shall serve until the second annual meeting following such succession or election. If the office of the Vice Chair becomes vacant for any reason, a new Vice Chair shall be elected at the next regular or special meeting and shall serve out the term of the Vice Chair whose office became vacant.

8.3.2 Duties of the Officers.

The Chair, the Vice Chair, or their representatives, shall: call and preside at meetings of the Administrative Committee; cause minutes of each meeting to be taken and maintained; cause notices of meetings to be distributed; and carry out such other responsibilities as the Administrative Committee shall assign or as may be specified in the Operating Agreement. The Vice Chair shall preside at meetings of the Administrative Committee if the Chair is absent for any reason, and shall otherwise act for the Chair at the Chair's request.

8.4 Meetings.

The Administrative Committee shall hold meetings no less frequently than once each calendar quarter. One of such regular meetings shall be designated as the annual meeting, at which officers shall be elected. The matters to be addressed at all meetings shall be specified in the agenda provided in the notice distributed pursuant to Section 8.4.1 hereof; provided, however, that action may be taken on a matter not described in such agenda, if approved by the Parties pursuant to a vote under Section 8.5.1.

8.4.1 Notice of Meetings.

Notice of a meeting shall be distributed to the representatives not later than ten (10) days prior to the meeting, provided, however, that meetings may be called on shorter notice at the discretion of the Chair as the Chair shall deem necessary to deal with an emergency or to meet a deadline for action. The notice shall state the time and place of such meeting, and shall include an agenda sufficient to notify the representatives of the substance of the matters to be considered at the meeting. In addition, notice of all meetings shall be provided over the PJM website at the same time as it is provided to the representatives.

8.4.2 Attendance.

Regular or special meetings may be conducted in person or by telephone or other means as authorized by the Administrative Committee. The attendance in person or by telephone or other means of a representative, alternate or duly-designated substitute representative shall be required for purposes of determining a quorum and for the exercise of Individual Votes or Weighted Votes.

8.4.3 Quorum.

To constitute a quorum with respect to any matter upon which a vote is taken, as of the date of any regular or special meeting, such meeting must be attended by either (i) representatives, alternates, or duly-designated substitute representatives whose Individual Votes constitute more than fifty percent (50%) of the total Individual Votes of Parties entitled to vote on such matter, and whose Weighted Votes constitute more than fifty percent (50%) of the total Weighted Votes of Parties entitled to vote on such matter, or (ii) representatives, alternates, or duly-designated substitute representatives whose Weighted Votes constitute at least ninety five percent (95%) of Parties entitled to vote on such matter. With respect to actions specified in Section 8.5.3, the Individual Votes of Zero Revenue Requirement Parties shall not be counted for purposes of determining the presence of a quorum.

8.4.4 Open Meetings.

Except as provided in this section, all meetings of the Administrative Committee shall be open to entities that are signatories to the Operating Agreement and to personnel of PJM, and all matters subject to Section 8.5.1 upon which the representatives vote shall be open to such entities and to such personnel. Meetings of the Administrative Committee shall be closed to persons or entities other than personnel of PJM if, in the determination of the Chair, doing so is required to comply with FERC's Standards of Conduct For Transmission Providers, Critical Energy Infrastructure Information, or Section 9.15, or shall be closed to all persons or entities other than personnel or representatives of the Parties in order to preserve the attorney-client, attorney work product or other privileges of the Parties or of the Administrative Committee.

8.4.5 Cost of Meetings.

Each Party shall be solely responsible for all costs incurred for its representative or alternate to attend any meeting. The Parties shall share the costs incurred by the host of any meeting of the Administrative Committee in the following manner. Fifty percent (50%) of such meeting cost shall be allocated in proportion to the Parties' Individual Votes and the remaining fifty percent (50%) of such meeting cost shall be allocated in proportion to the Parties' Weighted Votes. PJM shall accumulate costs and bill the Parties quarterly.

8.5 Manner of Acting.

Subject to the limitations of Section 9.7.1(a), any action taken by the Administrative Committee shall require a combination of the concurrence of the representatives' Individual Votes of the representatives of those Parties entitled to vote on such matters and Weighted Votes as specified in this Section 8.5.

8.5.1 Action by Two-thirds Majority.

The following actions of the Administrative Committee shall require the concurrence of: (i) representatives whose combined Individual Votes equal or exceed two-thirds of the total Individual Votes of Parties entitled to vote and cast at a meeting, provided, however, the vote shall not fail if voted against by representatives of Parties entitled to vote whose combined Weighted Votes do not exceed five percent (5%) of the total Weighted Votes cast; and (ii) representatives of Parties whose combined Weighted Votes equal or exceed two-thirds of the total Weighted Votes cast at a meeting, provided, however, that if the vote receives the concurrence of representatives whose combined Weighted Votes exceed one-half of the total Weighted Votes cast, the vote shall not fail if voted against by fewer than three Parties entitled to vote:

(a) Amendment or termination of all or any portion of this Agreement, including any schedules, appendices, or attachments hereto, provided that the text of any amendment shall be distributed by overnight courier, facsimile or other reliable electronic means at least thirty (30) days prior to the meeting at which such amendment is to be considered, and provided further that any amendment shall be submitted to FERC for filing and any termination shall not become effective until it shall have been approved by FERC or accepted without suspension or hearing;

(b) Development of comments and recommendations for the Regional Transmission Expansion Plan;

(c) Termination of a Party in accordance with the provisions of Section 9.7 hereof;

(d) Approval of an assignment of this Agreement pursuant to Section 9.5 hereof; and

(e) Approval of changes in or relating to Joint Transmission Rate or the PJM Regional Rate Design, or any provisions governing the recovery of transmission-related costs incurred by the Transmission Owners.

8.5.2 Action by Simple Majority.

Action by the Administrative Committee on any matter other than those specified in Section 8.5.1 shall require: (i) the presence of a quorum at the time of the vote; and (ii) the concurrence of: (a) representatives' whose combined Individual Votes exceed one-half of the total Individual Votes cast at a meeting, however, the vote shall not fail if voted against by representatives of Parties entitled to vote whose combined Weighted Votes do not exceed five percent (5%) of the total Weighted Votes cast; and (b) representatives' whose combined Weighted Votes exceed one-half of the total Weighted Votes cast at a meeting.

8.5.3

Anything contained herein to the contrary notwithstanding, a Zero Revenue Requirement Party shall not be entitled to vote on any matter described in Article 7, any matter described in Section 8.5.1 (e) or any amendment to this Agreement that would amend this Section 8.5.

8.5.4

Anything contained herein to the contrary notwithstanding, no vote to amend the definition of Applicable Regional Reliability Council, the application of such definition in within this Agreement, or to change the Applicable Regional Reliability Council of a Party shall pass without the affirmative vote of the representative of each Party whose Applicable Regional Reliability Council would be revised or changed as a result of such amendment.

ARTICLE 9 – OTHER MATTERS

9.1 Relationship of the Parties.

This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation liability upon any Party. Except as explicitly provided in Section 8.1 hereof or with respect to the actions of the Administrative Committee, neither PJM nor any Party shall have the right, power or authority under this Agreement to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, any other Party or PJM.

9.2 No Third-party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party (other than successors and permitted assigns) not a signatory hereto.

9.3 Term and Termination.

This Agreement shall be effective as of the Effective Date and shall continue in effect thereafter unless and until terminated by: (i) a vote of the Administrative Committee as of a specified date at least six (6) months after the date of such vote; or (ii) the termination of the Operating Agreement, unless the Administrative Committee decides not to terminate this Agreement or to terminate it at a later date. Termination may become effective only upon FERC's approval or acceptance without suspension or hearing.

9.4 Winding Up.

Any provision of this Agreement that, expressly or by implication, comes into or remains in force following termination or expiration of this Agreement shall survive such termination or expiration. Such surviving provisions shall include, but not be limited to: (i) those provisions necessary to permit the orderly conclusion or continuation, pursuant to another agreement, of transactions entered into prior to the decision to terminate this Agreement; (ii) those provisions necessary to conduct final billing, collection, and accounting with respect to all matters arising hereunder; and (iii) the indemnification provisions as applicable to periods prior to such termination or expiration.

9.5 Successors and Assigns.

This Agreement shall inure to the benefit of and be binding upon the Parties hereto, their respective successors and assigns permitted herein, but shall not be assignable by any Party without the approval of the Administrative Committee, except: (i) as to a successor in the operation of a Party's Transmission Facilities by reason of a merger, consolidation, reorganization, sale, spin-off, or foreclosure, as a result of which substantially all such Transmission Facilities are acquired by such a successor, and such successor becomes a Party to this Agreement; or (ii) as an assignment of rights under this Agreement for financing purposes.

9.6 Force Majeure.

No Party shall be liable to any other Party for damages or otherwise be in breach of this Agreement to the extent and during the period such Party's performance is prevented by any cause or causes beyond such Party's control and without such Party's fault or negligence, including but not limited to any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities; provided, however, that any such foregoing event shall not excuse any payment obligation. Upon the occurrence of an event considered by a Party to constitute a force majeure event, such Party shall use due diligence to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that no Party shall be required by this provision to settle any strike or labor dispute.

9.7 Default and Waiver

9.7.1 Default.

Any Party that fails to meet its financial or other obligations to another Party or to PJM under this Agreement shall be deemed to be in breach of this Agreement. If the Administrative Committee concludes, upon the report of PJM or complaint of any Party that another Party is in breach, the Administrative Committee shall so notify such Party and inform all other Parties. The notified Party may remedy such breach by: (i) paying all amounts assertedly due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); and (ii) presenting evidence satisfactory to the Administrative Committee that it has taken appropriate measures to meet any other obligation of which it was deemed to be in breach; provided, however, that any such payment or presentation may be subject to a reservation of rights, if any, to a final determination of the obligations of the Party pursuant to the dispute resolution provisions in the Operating Agreement. If, by the thirtieth (30th) day following receipt of the foregoing notice, a Party has not remedied the breach, then such Party shall be in default, and in addition to any other remedies then available:

(a) Any representative of the defaulting Party on the Administrative Committee, or any other committee, subcommittee, working group or task force established pursuant to this Agreement, shall not be entitled to vote for so long as the default shall continue to exist.

(b) If the default is the Party's second default within a period of twenty-four months, or is a default that imperils the safety or reliability of the PJM Region, the Administrative Committee may vote to terminate the Party's status as a Party to this Agreement. A terminated Party shall comply with all obligations applicable to a Party withdrawing from this Agreement.

9.7.2 No Implied Waivers.

The failure of a Party or of the Administrative Committee to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such entity's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

9.8 Indemnification.

9.8.1

Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (not including PJM and the PJM Board) for all actions, claims, demands, costs, damages and liabilities asserted by a third party against the Party seeking indemnification and arising out of or relating to any of the Transmission Facilities or other assets that are the subject of this Agreement of the Party from which indemnification is sought, or an act or failure to act in accordance with this Agreement by such Party, except: (i) to the extent that such liabilities result from the negligence or willful misconduct of the Party seeking indemnification; and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law.

9.8.2

The amount of any indemnity payment arising hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified action, claim, demand, costs, damage or liability. If any Party shall have received an indemnity payment for an action, claim, demand, cost, damage or liability and shall subsequently actually receive insurance proceeds or other amounts for such action, claim, demand, cost, damage or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

9.9 Limitations on Liability.

No Party shall be liable to any other Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party, including, but not limited to, loss of profits or revenues, cost of capital of financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failing to carry out, any obligations contemplated by this Agreement except to the extent the damages are direct damages that result from the gross negligence or intentional misconduct of such party; provided, however, that nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a Party to this Agreement. To the extent that any Party has a claim against any other Party, the amount of any judgement or arbitration award on such claim entered in favor of such Party shall be limited to the value of that Party's assets. The Parties may not seek to enforce claims against the directors, managers, members, shareholders, officers, or employees of any other Party who shall have no personal liability for obligations of such Party by reason of their status as directors, managers, members, shareholders, officers or employees.

9.10 PJM's Liability.

The liability of PJM, its Board, officers, employees, and agents shall be governed by the applicable provisions of the PJM Tariff and Operating Agreement.

9.11 Governing Law.

This Agreement shall be interpreted, construed and governed by the laws of the state of Delaware exclusive of the conflicts of laws provisions.

9.12 Notice.

Except as otherwise expressly provided herein, notices required hereunder shall be in writing and shall be sent to a Party by overnight courier, hand delivery, telecopier or other reliable electronic means to the representative on the Administrative Committee of such Party at the address for such Party previously provided by such Party to the other Parties or as otherwise directed by the Administrative Committee. Any such notice so sent shall be deemed to have been given: (i) upon delivery if given by overnight couriers or hand delivery; or (ii) upon confirmation if given by telecopier or other reliable electronic means.

9.13 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all Parties hereto, notwithstanding that all such Parties may not have executed the same counterpart.

9.14 Representations and Warranties.

Each Party represents and warrants to the other Parties that, as of the date it becomes a Party.

9.14.1

The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

9.14.2

The execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

9.14.3

There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

9.15 Confidentiality

9.15.1 Party Access.

No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to PJM, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by PJM or to the extent that they have been designated as confidential by such other Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Party's confidential data or information.

9.15.2 Maintenance of Confidential Information.

In the course of performing functions under this Agreement, the Parties may from time to time receive from each other or from PJM information that a Party or PJM may designate as confidential, or which is subject to FERC's Standards of Conduct for Transmission Providers, or Critical Energy Infrastructure Information, as amended from time to time. The Parties shall treat such information as confidential in accordance with a nondisclosure agreement adopted by the Administrative Committee. Information subject to FERC's Standards of Conduct for Transmission Providers or Critical Energy Infrastructure Information shall not be disclosed or shared except as permitted thereby.

9.16 Severability and Renegotiation

9.16.1 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

9.16.2 Renegotiation.

If any provision of this Agreement is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if the Agreement is modified or conditioned by a regulatory authority exercising jurisdiction over this Agreement, the Parties shall endeavor in good faith to negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the Parties under this Agreement immediately prior to such holding, modification or condition. If after 60 days such negotiations are unsuccessful the Parties may exercise their withdrawal or termination rights under this Agreement.

9.17 Insurance.

Each Party shall obtain and maintain in force such insurance as is consistent with Good Utility Practice.

9.18 Headings.

The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

9.19 Disputes Between a Party and PJM.

To the extent any dispute arises between one or more Parties and PJM regarding any issue covered by this Agreement, the Party and PJM shall follow the dispute resolution procedures set forth in the dispute resolution procedures provided as Schedule 5 to the Operating Agreement.

9.20 Changes to Applicable Regional Reliability Council.

Notwithstanding anything in this Agreement, the Parties agree and acknowledge that any Party that files a request or complaint with FERC pursuant to Section 206 of the Federal Power Act to amend the definition of Applicable Regional Reliability Council or the application of such definition within this Agreement, or to change the Applicable Regional Reliability Council of a Party agrees that such request or complaint shall be submitted pursuant to the "public interest" standard of Section 206, as set forth in *United Gas Pipe Line Co. v. Mobile Gas Services Corp., 350 U.S. 332 (1956* and *Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956)*, provided, however, such Mobile-Sierra "public interest" standard shall not apply to FERC ordered changes pursuant to Section 206 of the Federal Power Act to amend the definition of Applicable Regional Reliability Council or the application of such definition within this Agreement, or to change the Applicable Regional Reliability Council of a Party.

9.21 Prior Agreements Superseded.

As of the Effective Date of this Agreement, the Transmission Owners Agreement dated as of June 2, 1997, as amended, the West Transmission Owners Agreement dated as of March 13, 2001, as amended and restated December 2, 2002, and the PJM South Transmission Owner Agreement dated May 11, 2004 shall be superseded in accordance with the terms of this Agreement.

9.22 Relationship to Superseded Agreements.

Upon the Effective Date of this Agreement, each Party shall maintain its rights and remain liable for any and all obligations under: (i) the Transmission Owners Agreement dated as of June 2, 1997, as amended: (ii) the West Transmission Owners Agreement dated as of March 13, 2001, as amended and restated December 2, 2002; or (iii) the PJM South Transmission Owner Agreement dated May 11, 2004 (collectively "the Superseded Agreements") applicable to such Party that arose under a Superseded Agreement with respect to such Party prior to the Effective Date of this Agreement. Neither the effectiveness of this Agreement nor the termination of the Superseded Agreements shall relieve the Parties of any of their indemnification or liability obligations contained in the Superseded Agreements for any events occurring prior to the Effective Date of this Agreement.

ATTACHMENT A

TO THE CONSOLIDATED

TRANSMISSION OWNERS AGREEMENT

Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power

American Electric Power Service Corporation on behalf of its affiliate companies: AEP Appalachian Transmission Company, Inc.; AEP Indiana Michigan Transmission Company, Inc.; AEP Kentucky Transmission Company, Inc.; AEP Ohio Transmission Company, Inc.; AEP West Virginia Transmission Company, Inc.; Appalachian Power Company; Indiana Michigan Power Company; Kentucky Power Company; Kingsport Power Company; Ohio Power Company and Wheeling Power Company

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Dayton Power and Light Company

Virginia Electric and Power Company (Dominion Virginia Power)

Public Service Electric and Gas Company

PECO Energy Company

PPL Electric Utilities Corporation

Baltimore Gas and Electric Company

Jersey Central Power & Light Company

Potomac Electric Power Company

Atlantic City Electric Company

Delmarva Power & Light Company

UGI Utilities, Inc.

Allegheny Electric Cooperative, Inc.

Essential Power Rock Springs, LLC

Old Dominion Electric Cooperative

Rockland Electric Company

Duquesne Light Company

Neptune Regional Transmission System, LLC

Trans-Allegheny Interstate Line Company

Linden VFT, LLC

American Transmission Systems, Incorporated

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

Duke Energy Ohio, Inc.

Duke Energy Kentucky, Inc.

City of Hamilton, OH

Hudson Transmission Partners, LLC

East Kentucky Power Cooperative, Inc.

Mid-Atlantic Interstate Transmission, LLC

Southern Maryland Electric Cooperative, Inc.

Ohio Valley Electric Cooperative

AMP Transmission, LLC

Transource West Virginia, LLC

Silver Run Electric, LLC

NextEra Energy Transmission MidAtlantic Indiana, Inc.

Wabash Valley Power Association, Inc.

Keystone Appalachian Transmission Company

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PJM Interconnection, L.L.C.

By: ___________________________________
Name: Phillip G. Harris
Title: President and CEO
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power

By: ______________________________
Name: Olenger L. Pannell
Title: Vice President
Date: January 1, 2024

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Electric Power Service Corporation on behalf of its affiliate companies: AEP Appalachian Transmission Company, Inc.; AEP Indiana Michigan Transmission Company, Inc.; AEP Kentucky Transmission Company, Inc.; AEP Ohio Transmission Company, Inc.; AEP West Virginia Transmission Company, Inc.; Appalachian Power Company; Indiana Michigan Power Company; Kentucky Power Company; Kingsport Power Company; Ohio Power Company and Wheeling Power Company

By:________________________________
Name: Lisa M. Barton
Title: Executive Vice President - AEP Transmission
Date: October 13, 2015

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiaries
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

By:_________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

The Dayton Power and Light Company

By: ___________________________________
Name: Patricia K. Swanke
Title: Vice President - Operations
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Virginia Electric and Power Company (Dominion Virginia Power)

By:_________________________________
Name: Gary L. Sypolt
Title: President – Dominion Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Public Service Electric and Gas Company

By: ________________________________
Name: Ralph LaRossa
Title: Vice President - Electric Delivery
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiary
PECO Energy Company

By:___________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PPL Electric Utilities Corporation

By:___________________________________
Name: John F. Sipics
Title: President
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Baltimore Gas and Electric Company

By:_____________________________
Name: Mark P. Huston
Title: Vice President, Electric Transmission and Distribution
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Jersey Central Power & Light Company

By: ________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Potomac Electric Power Company

By:_____________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Atlantic City Electric Company

By: _________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Delmarva Power & Light Company

By:_________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

UGI Utilities, Inc.

By: ___________________________
Name: Richard E. Gill
Title: Assistant Secretary - Electric Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Essential Power Rock Springs, LLC

By:________________________________
Name: Jason Solimini
Title: Vice President Finance, Controller and Treasurer
Date: September 26, 2019

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Old Dominion Electric Cooperative

By:_________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Rockland Electric Company

By:_________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duquesne Light Company

By:_________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Allegheny Electric Cooperative, Inc.

By: ___________________________________
Name: Richard W. Osborne
Title: Vice President Power Supply & Engineering
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Neptune Regional Transmission System, LLC

By: _________________________________
Name: Edward M. Stern
Title: CEO
Date: March 7, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Trans-Allegheny Interstate Line Company

By: ________________________________
Name: James R. Haney
Title: Vice President
Date: November 8, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Linden VFT, LLC

By: ________________________________
Name: Andrew J. Keleman
Title: Authorized Representative
Date: April 1, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Transmission Systems, Incorporated

By: ________________________________
Name: Richard R. Grigg
Title: President
Date: December 17, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

City of Cleveland, Department of Public Utilities
Division of Cleveland Public Power

By: ______________________________
Name: Barry A. Withers
Title: Director
Date: March 22, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Ohio, Inc.

By: ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Kentucky, Inc.

By: ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

City of Hamilton, OH

By: ______________________________
Name: Joshua A. Smith
Title: City Manager
Date: February 29, 2012

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Hudson Transmission Partners, L.L.C.

By: ________________________________
Name: Jeffrey T. Wood
Title: Senior Vice President
Date: February 8, 2013

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

East Kentucky Power Cooperative, Inc.

By: ________________________________
Name: Anthony S. Campbell
Title: President & CEO
Date: March 26, 2013

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Mid-Atlantic Interstate Transmission, LLC

By:______________________________
Name: Richard A. Ziegler
Title: Director, FERC & RTO Technical Support
Date: October 14, 2016

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Southern Maryland Electric Cooperative, Inc.

By:_______________________________
Name: Austin J. Slater, Jr.
Title: President & CEO
Date: October 19, 2016

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Ohio Valley Electric Corporation, Inc.

By:__________________________________
Name: Justin J. Cooper
Title: Secretary, Treasurer, and Chief Financial Officer
Date: November 28, 2018

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

AMP Transmission, LLC

By: ________________________________
Name: Pamala M. Sullivan
Title: President
Date: October 9, 2018

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Transource West Virginia, LLC

By: ___________________________
Name: Antonio P. Smyth
Title: President
Date: February 19, 2019

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Silver Run Electric, LLC

By: ___________________________
Name: Paul G. Thessen
Title: President
Date: February 27, 2020

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

NextEra Energy Transmission MidAtlantic Indiana, Inc.

By:______________________________
Name: Michael Sheehan
Title: Vice President
Date: May 7, 2020

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Wabash Valley Power Association, Inc.

By: ________________________________
Name: Jay Bartlett
Title: Chief Executive Officer
Date: 10/25/19

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Keystone Appalachian Transmission Company

By: ______________________________
Name: Olenger L. Pannell
Title: Vice President
Date: January 1, 2024

PJM Interconnection, L.L.C.
Rate Schedule FERC No. 44

RELIABILITY ASSURANCE AGREEMENT

Among

LOAD SERVING ENTITIES

in the

PJM REGION

PJM RELIABILITY ASSURANCE AGREEMENT

TABLE OF CONTENTS

RELIABILITY ASSURANCE AGREEMENT

RELIABILITY ASSURANCE AGREEMENT, dated as of this 1st day of June, 2007 by and among the entities set forth in Schedule 17 hereto, hereinafter referred to collectively as the "Parties" and individually as a "Party."

WITNESSETH:

WHEREAS, each Party to this Agreement is a Load Serving Entity within the PJM Region;

WHEREAS, each Party is committing to share its Capacity Resources with the other Parties to reduce the overall reserve requirements for the Parties while maintaining reliable service; and

WHEREAS, each Party is committing to provide mutual assistance to the other Parties during Emergencies;

WHEREAS, each Party is committing to coordinate its planning of Capacity Resources to satisfy the Reliability Principles and Standards; and

NOW THEREFORE, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

"Accredited UCAP Factor" shall mean, through the 2024/2025 Delivery Year, one minus EFORd, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

"Capacity Resources" shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

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 the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

"Demand Resource Sell Offer Plan" shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

Effective Nameplate Capacity:

"Effective Nameplate Capacity" shall mean (i) for each Variable Resource and Combination Resource, the resource's Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility's Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource's capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility's Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

"Effective UCAP" shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

"ELCC Class" shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

"ELCC Class Rating" shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

"ELCC Class UCAP" shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

"ELCC Portfolio UCAP" shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

"ELCC Resource" shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

"ELCC Resource Performance Adjustment" shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

"Electric Cooperative" shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

"Electric Distributor" shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

"Emergency" shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

“Exigent Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery

Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

"Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

"Facilities Study Agreement" shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall have the meaning specified in the Tariff.

Firm Service Level:

"Firm Service Level" or "FSL" of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. "Firm Service Level" or "FSL" of Demand Resource shall mean the pre-determined level for which an end-use customer's load shall be reduced, upon notification from the Curtailment Service Provider's market operations center or its agent.

Firm Transmission Service:

"Firm Transmission Service" shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

"Fixed Resource Requirement Alternative" or "FRR Alternative" shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

"Fixed-Tilt Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

"Forecast Pool Requirement" or "FPR" shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

"FRR Capacity Plan" or "FRR Plan" shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

"FRR Entity" shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

"FRR Service Area" shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

"Full Program Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

"Full Requirements Service" shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

"Gas Combined Cycle Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

"Gas Combined Cycle Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery

Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

"Hybrid Resource Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in a Capacity Storage Resource Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

"Hydropower With Non-Pumped Storage" shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

"Hydropower With Non-Pumped Storage Class" shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

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, Accredited UCAP Factor decrease, 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.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Limited Demand Resource:

"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

"Locational Reliability Charge" shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

"Markets and Reliability Committee" shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

"Maximum Emergency Service Level" or "MESL" of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Members Committee:

"Members Committee" shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

"Network Resources" shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

"Non-Retail Behind the Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

"Offshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

"Onshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

"Operating Day" shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

"Operating Reserve" shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

"Ordinary Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

"Other Limited Duration Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

"Other Limited Duration Combination Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

“Other Unlimited Resource Class” shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

“Other Variable Resource Class” shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

“Peak Shaving Adjustment” shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any end-use customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

"Performance Assessment Interval" shall have the meaning specified in Tariff, Attachment DD.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

"PJM Region" shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T., "OATT" or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

"Planned Demand Resource" shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

"Planning Period" shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

"Portfolio Expected Unserved Energy" shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

"PRD Curve" shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

"PRD Provider" shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider's Zonal Expected Peak Load Value of PRD:

"PRD Provider's Zonal Expected Peak Load Value of PRD" shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

"PRD Reservation Price" shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

"PRD Substation" shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads**.**

Price Responsive Demand:

"Price Responsive Demand" or "PRD" shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

"Price Responsive Demand Credit" shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

"Price Responsive Demand Plan" or "PRD Plan" shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider's Nominal PRD Value.

Public Power Entity:

"Public Power Entity" shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

"Qualifying Transmission Upgrades" shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" or "RERRA" shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

"Reliability Principles and Standards" shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

"Required Approvals" shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

"Self-Supply" shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

"Small Commercial Customer" shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

"State Regulatory Structural Change" shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

"Threshold Quantity" shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Reliability Assurance Agreement, Schedule 8.1).

Tracking Solar Class:

"Tracking Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

"Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

"Unlimited Resource" shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

"Variable Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

"Winter Peak Load" or "WPL" shall mean the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

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.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

ARTICLE 2 -- PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, and Energy Efficiency Resources will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in RAA, Article 3, section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

ARTICLE 3 -- TERM AND TERMINATION OF THE AGREEMENT

3.1 Term.

This Agreement shall become effective as of June 1, 2007 and shall govern Unforced Capacity Obligations for the Planning Period beginning as of that date (“Initial Delivery Year”), and for each Planning Period thereafter, unless and until terminated in accordance with the terms hereof.

3.2 [Reserved for Future Use]

3.3 Termination.

3.3.1 Rights to Terminate.

This Agreement may be terminated by a vote in the Members Committee to terminate the Agreement by an affirmative Sector Vote as specified in the Operating Agreement and upon the receipt of all Required Approvals related to the termination of this Agreement. Any such termination must be approved by the PJM Board and filed with the FERC and shall become effective only upon the FERC's approval.

3.3.2 Obligations upon Termination.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (a) final settlement of the obligations of each Party under RAA, Article 8 and RAA, Article 12, including the accounting for the period ending with the last day of the month for which the Agreement is effective, (b) the provisions of this Agreement necessary to conduct final billings, collections and accounting with respect to all matters arising hereunder and (c) the indemnification provisions as applicable to periods prior to such termination.

ARTICLE 4 -- ADDITION OF NEW PARTIES

Each Party agrees that any entity that (i) is or will become a Load Serving Entity, (ii) complies with the process and data requirements set forth in RAA, Schedule 1, and (iii) meets the standards for interconnection set forth in RAA, Schedule 2 shall become a Party to this Agreement and shall be listed on RAA, Schedule 17 upon becoming a party to the Operating Agreement, and execution of a counterpart of this Agreement.

ARTICLE 5 -- WITHDRAWAL OR REMOVAL OF A PARTY

5.1 Withdrawal of a Party.

5.1.1 Notice.

Upon written notice to the Office of the Interconnection, any Party may withdraw from this Agreement, effective upon the completion of its obligations hereunder and the documentation by such Party, to the satisfaction of the Office of the Interconnection, that such Party is no longer a Load Serving Entity.

5.1.2 Determination of Obligations.

A Party's obligations hereunder shall be completed as of the end of the last month for which such Party's obligations have been set at the time said notice is received, except as provided in RAA, Article 13, or unless the Members Committee determines that the remaining Parties will be able to adjust their obligations and commitments related to the performance of this Agreement consistent with such earlier withdrawal date as may be requested by the withdrawing Party, without undue hardship or cost, while maintaining the reliability of the PJM Region.

5.1.3 Survival of Obligations upon Withdrawal.

(a) The obligations of a Party upon its withdrawal from this Agreement and any obligations of that Party under this Agreement at the time of its withdrawal shall survive the withdrawal of the Party from this Agreement. Upon the withdrawal of a Party from this Agreement, final settlement of the obligations of such Party under RAA, Article 7 and RAA, Article 11 shall include the accounting through the date established pursuant to RAA, Article 5, section 5.1.1 and RAA, Article 5, section 5.1.2.

(b) Any Party that withdraws from this Agreement shall pay all costs and expenses associated with additions, deletions and modifications to communication, computer, and other affected facilities and procedures, including any filing fees, to effect the withdrawal of the Party from the Agreement.

(c) Prior to withdrawal, a withdrawing Party desiring to remain interconnected with the PJM Region shall enter into a control area to control area interconnection agreement with the Office of the Interconnection and the transmission owner or Electric Distributor within the PJM Region with which its facilities are interconnected.

5.1.4 Regulatory Review.

Any withdrawal from this Agreement shall be filed with FERC and shall become effective only upon FERC's approval.

5.2 Breach by a Party.

The provisions of Operating Agreement, section 15.1 shall apply to a Party’s (a) failure to pay any amount due under this Agreement when due or (b) breach of any material obligation under this Agreement. In addition to the remedies available to the Office of the Interconnection set forth in Operating Agreement, section 15.1, if the Party fails to cure such non-payment or breach, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (a) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (b) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys’ fees).

ARTICLE 6 -- MANAGEMENT ADMINISTRATION

Except as otherwise provided herein, this Agreement shall be managed and administered by the Parties, Members, and State Consumer Advocates through the Members Committee and the Markets and Reliability Committee as a Standing Committee thereof, except as delegated to the Office of the Interconnection and except that only the PJM Board shall have the authority to approve and authorize the filing of amendments to this Agreement with the FERC.

ARTICLE 7 -- RESERVE REQUIREMENTS AND OBLIGATIONS

7.1 Forecast Pool Requirement and Unforced Capacity Obligations.

(a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. RAA, Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

7.2 Responsibility to Pay Locational Reliability Charge.

Except to the extent its capacity obligations are satisfied through the FRR Alternative, each Party shall pay, as to the loads it serves in each Zone during a Delivery Year, a Locational Reliability Charge for each such Zone during such Delivery Year. The Locational Reliability Charge shall equal such Party's Daily Unforced Capacity Obligation in a Zone, as determined pursuant to RAA, Schedule 8, times the Final Zonal Capacity Price for such Zone, as determined pursuant to Tariff, Attachment DD.

7.3 LSE Option to Provide Capacity Resources.

A Party obligated to pay a Locational Reliability Charge for a Delivery Year may partially or wholly offset amounts it must pay for such charge by offering Capacity Resources for sale in the Base Residual Auction or an Incremental Auction applicable to such Delivery Year; provided such resources clear such auctions. Resources offered for sale in any such auction must satisfy the requirements specified in this Agreement and the PJM Manuals. Such a Party may choose to nominate a resource in the Base Residual Auction as Self-Supply, may choose to designate a price offer for such resource into any such auction, or may indicate in its offer that it wishes to commit such resource regardless of the clearing price, in which case the Party shall receive the marginal value of system capacity and the price adders for any applicable binding locational constraint in accordance with Attachment DD of the PJM Tariff. Each such Party acknowledges that the clearing price it receives for a resource offered for sale and cleared, or Self-Supplied, in an auction may differ from the Final Zonal Capacity Price determined for the applicable Zone for the applicable Delivery Year, and that the Party shall remain responsible for the Locational Reliability Charge notwithstanding any such difference between the Capacity Resource Clearing Price and the Final Zonal Capacity Price. In addition, such Parties recognize that they may receive an allocation of Capacity Transfer Rights which may offset a portion of the Locational Reliability Charge, and that they may offset a portion of the Locational Reliability Charge by offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

7.4 Fixed Resource Requirement Alternative.

A Party that is eligible for the Fixed Resource Requirement Alternative may satisfy its obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan and meeting all other terms and conditions of such alternative, as set forth in this Agreement.

7.5 Capacity Plans and Deliverability.

Each Party electing to provide Capacity Resources to meet its obligations hereunder shall submit to the Office of the Interconnection its plans (or revisions to previously submitted plans), as prescribed by RAA, Schedule 7, or, in the case of a Party electing the FRR Alternative, as prescribed by RAA, Schedule 8.1, to install or contract for Capacity Resources. As set forth in RAA, Schedule 10, each Party must designate its Capacity Resources as Network Resources or Points of Receipt under the PJM Tariff to allow firm delivery of the output of its Capacity Resources to the Party's load within the PJM Region and each Party must obtain any necessary Firm Transmission Service in an amount sufficient to deliver Capacity Resources from outside the PJM Region to the border of the PJM Region to reliably serve the Party's load within the PJM Region.

7.6 Nature of Resources.

Each Party electing to Self-Supply resources, or electing the FRR Alternative, shall provide or arrange for specific, firm Capacity Resources that are capable of supplying the energy requirements of its own load on a firm basis without interruption for economic conditions and with such other characteristics that are necessary to support the reliable operation of the PJM Region, as set forth in more detail in RAA, Schedule 6, RAA, Schedule 9 and RAA, Schedule 10.

7.7 Compliance Audit of Parties.

(a) For the 36 months following the end of each Planning Period, each Party shall make available the records and supporting information related to the performance of this Agreement from such Planning Period for audit.

(b) The Office of the Interconnection shall evaluate and determine the need for an audit of a Party and shall, upon a decision of the Members Committee to require such an audit, provide the Party or Parties to be audited with notice at least 90 days in advance of the audit.

(c) Any audit of a Party conducted pursuant to this Agreement shall be performed by an independent consultant to be selected by the Office of the Interconnection. Such audit shall include a review of the Party's compliance with the procedures and standards adopted pursuant to this Agreement.

(d) Prior to the completion of its audit, the independent consultant shall review its preliminary findings with the Party being audited and, upon the completion of its audit, the independent consultant shall issue a final audit report detailing the results of the audit, which final report shall be issued to the Party being audited, the Office of the Interconnection and the Markets and Reliability Committee; provided, however, no confidential data of any Party shall be disclosed through such audit reports.

(e) If, based on a final audit report, an adjustment is required to any amounts due to or from the Parties pursuant to Schedules 8, 12, or 13, such adjustment shall be accounted for in determining the amounts due to or from the Parties pursuant to Schedules 8, 12, or 13 for the month in which the adjustment is identified.

ARTICLE 8 -- DEFICIENCY, DATA SUBMISSION, AND EMERGENCY CHARGES

8.1 Nature of Charges.

Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement.

8.2 Determination of Charge Amounts.

No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period , which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.

8.3 Distribution of Charge Receipts.

All of the monies received as a result of any charges imposed pursuant to this Agreement shall be disbursed as provided in this Agreement.

ARTICLE 9 -- COORDINATED PLANNING AND OPERATION

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a) cooperate with the members and associate members of such Party's Applicable Regional Entity to ensure the reliability of the region;

(b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.2 Generator Planned Outage Scheduling.

Each Party shall develop, or cause to be developed, its schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, in RAA, Schedule 11.

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Tariff, Attachment DD, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.

(b) A data submission charge, as set forth in RAA, Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in RAA, Schedule 11.

9.5 Metering.

Each Party shall comply with the metering standards for the PJM Region, as set forth in the PJM Manuals, as well as any further metering requirements applicable to Price Responsive Demand, where such is relied upon for an adjustment to peak load pursuant to RAA, Schedule 6.1.

ARTICLE 10 -- SHARED COSTS

10.1 Recording and Audit of Costs.

(a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

10.2 Cost Responsibility.

The costs determined under RAA, Article 10, section 10.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Tariff, Schedule 9-5.

ARTICLE 11 -- BILLING AND PAYMENT

11.1 Periodic Billing.

Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Party's share of any costs allocated to that Party pursuant to RAA, Article 10. To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Operating Agreement or PJM Tariff.

11.2 Payment.

The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

11.3 Failure to Pay.

If any Party fails to pay its share of the costs allocated pursuant to Article 10, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Daily Unforced Capacity Obligations of each such Party for the billing month. The Office of the Interconnection shall enforce collection of a Party's share of the costs.

ARTICLE 12 -- INDEMNIFICATION AND LIMITATION OF LIABILITIES

12.1 Indemnification.

(a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (other than PJM Interconnection, L.L.C., its board or the Office of the Interconnection) for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law. Nothing herein shall limit a Party's indemnity obligations under Operating Agreement, section 16.

(b) The amount of any indemnity payment under this section 12.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

12.2 Limitations on Liability.

No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

12.3 Insurance.

Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM Region.

ARTICLE 13 -- SUCCESSORS AND ASSIGNS

13.1 Binding Rights and Obligations.

The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

13.2 Consequences of Assignment.

Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of RAA, Article 13, section 13.1, the assignor shall be deemed to have withdrawn from this Agreement.

ARTICLE 14 -- NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

ARTICLE 15 -- REPRESENTATIONS AND WARRANTIES

15.1 Initial Representations and Warranties.

Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

(b) the execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

(c) there are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

15.2 Continuing Representations and Warranties.

Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of RAA, Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in RAA, Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

ARTICLE 16 -- OTHER MATTERS

16.1 Relationship of the Parties.

This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

16.2 Governing Law.

This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

16.3 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

16.4 Amendment.

This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an Applicant eligible to become a Party in accordance with the procedures set forth in RAA, Article 4 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The PJM Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

16.5 Headings.

The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

16.6 Confidentiality.

(a) No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by another Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite document does not disclose any individual Party's confidential data or information.

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

16.7 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

16.8 No Implied Waivers.

The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

16.9 No Third Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

16.10 Dispute Resolution.

Except as otherwise specifically provided in the Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Operating Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

[Signatures]

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM Region and thus a Party to the Reliability Assurance Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date the Reliability Assurance Agreement is to become effective as to that entity) satisfy the requirements to become a Party, (ii) all data required to coordinate planning and operations within the PJM Region as applicable, in a format defined in the PJM Manuals, and (iii) a deposit in an amount to be specified that will be applied toward the costs of the required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

- If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for transmission service under the PJM Tariff.

- If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM Region or (ii) in which any agency relationship through which the entity's obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Tariff associated with providing service to those loads.

B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM Region.

C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entity's share of any costs pursuant to RAA, Article 10, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Markets and Reliability Committee and execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Region's interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Region's standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

- Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 9.1(d); and

- The Operating Agreement.

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than 75 days in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in RAA, Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) seasonal peak diversities determined by the Office of the Interconnection.

2. Variability of loads within each week through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, hourly load shapes and variability, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

3. Generating unit capability and types for every existing and proposed unit.

4. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent and historical experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

5. Generator Maintenance Outage factors and planned outage factors as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

6. Miscellaneous adjustments to capacity due to all causes, including weather, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

7. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

D. Capacity Benefit Margin

The capacity benefit margin initially shall be 3,500 megawatts. Periodically, in consultation with the Members Committee, the Office of the Interconnection shall review and modify, if necessary, the capacity benefit margin to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the Parties, consistent with the Reliability Principles and Standards. The Office of the Interconnection will reflect such modification prospectively in its development of the Forecast Pool Requirement for future Planning Periods.

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Through the 2024/2025 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (1 - \text{Pool-wide average } EFOR_D)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. Through the 2024/2025 Delivery Year, the PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to RAA, Schedule 5.

C. Beginning with the 2025/2026 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (\text{Pool-wide average Accredited UCAP Factor})$$

where

Pool-wide average Accredited UCAP Factor = the ratio of the total Accredited UCAP to total installed capacity of all resources, as determined pursuant to RAA, Schedule 9.2, that are included in the determination of the Forecast Pool Requirement, stated in percent

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D\ (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For Delivery Years through the 2024/2025 Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year.

Such calculation shall be based upon such resource’s service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

For Delivery Years through the 2024/2025 Delivery Year, the forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand

Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource’s offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer’s energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter

Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter, Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and

winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric

Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller’s deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

SCHEDULE 6.1

PRICE RESPONSIVE DEMAND

A. As more fully set forth in this Schedule 6.1 and the PJM Manuals, for any Delivery Year beginning on or after June 1, 2015 (subject to a transition plan, as set forth below), any PRD Provider, including any FRR Entity, may commit that certain loads identified by such PRD Provider shall not exceed a specified demand level at specified prices during Maximum Generation Emergencies for the 2020/2021 and 2021/2022 Delivery Years or at specified prices during a Performance Assessment Interval for the 2022/2023 Delivery Year and subsequent Delivery Years, as a consequence of the implementation of Price Responsive Demand. Based on information provided by the PRD Provider in a PRD Plan (and, to the extent such plan identifies a PRD Reservation Price, based on the clearing price in the Base Residual Auction or Third Incremental Auction, as applicable), the Office of the Interconnection shall determine the Nominal PRD Value for the specified loads identified by such PRD Provider by Zone (or sub-Zonal LDA, if applicable). The Office of the Interconnection shall adjust the PJM Region Reliability Requirement and LDA Reliability Requirements, as applicable, to reflect committed PRD. Actual PRD reductions in response to price shall be added back in determining peak load contributions as set forth in the PJM Manuals. Any PRD Provider that fails to fully honor its PRD commitments for a Delivery Year shall be assessed compliance charges.

B. End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response, Pre-Emergency Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider; or (iv) include Critical Natural Gas Infrastructure.

C. Any PRD Provider seeking to commit PRD hereunder for a Delivery Year must submit to the Office of the Interconnection a PRD Plan identifying and supporting the Nominal PRD Value (for the 2020/2021 and 2021/2022 Delivery Years, calculated as the difference between the PRD Provider's Zonal Expected Peak Load Value of PRD and the Maximum Emergency Service Level of Price Responsive Demand or for the 2022/2023 Delivery Year and subsequent Delivery Years, calculated as the peak load contribution minus Firm Service Level times loss factor for each Zone (or sub-Zonal LDA, if applicable) for which such PRD is committed; such information shall be provided on a PRD Substation level to the extent available at the time the PRD Plan is submitted. Such plan must be submitted no later than (a) March 17, 2019 for the Base Residual Auction for the 2022/2023 Delivery Year or (b) the January 15 that last precedes the Base Residual Auction for the 2023/2024 and subsequent Delivery Years for which such PRD is committed; any submitted plan that does not contain, by such applicable deadline, all information required hereunder shall be rejected. A PRD Provider may submit a PRD Plan, or a modified PRD Plan, by the January 15 last preceding the Third Incremental Auction for such Delivery Year requesting approval of additional Price Responsive Demand but only in the event, and to the extent, that the final peak load forecast for the relevant LDA for such Delivery Year exceeds the preliminary peak load forecast for such LDA and Delivery Year. Notwithstanding the foregoing, any PRD Plan submitted and approved for the 2022/2023 Delivery Year may be withdrawn or modified no later than 30 days prior to the commencement of the Base Residual Auction. The Office of the Interconnection shall revise such requests (as adjusted, to the extent a PRD Reservation Price is specified, for the results of the Third Incremental Auction) for additional Price Responsive Demand downward, in accordance with rules in the PJM Manuals, if the submitted requests (as adjusted) in the aggregate exceed the increase in the load forecast in the LDA modeled. The Office of the Interconnection shall advise the PRD Provider, following the Third Incremental Auction, of its acceptance of, or any downward adjustment to, the Nominal PRD Value based on its review of the PRD Plan and the results of the auction. Approval of the PRD Plan by the Office of the Interconnection shall establish a firm commitment by the PRD Provider to the specified Nominal PRD Value of Price Responsive Demand at each Zone (or sub-Zonal LDA, if applicable) during the relevant Delivery Year (subject to any PRD Reservation Price), and may not be uncommitted or replaced by any Capacity Resource. Although the PRD Plan may include reasonably supported forecasts and expectations concerning the development of Price Responsive Demand for a Delivery Year, the PRD Provider's commitment to a Nominal PRD Value for such Delivery Year shall not depend or be conditioned upon realization of such forecasts or expectations.

D. All submitted PRD Plans must comply with the requirements and criteria in the PJM Manuals for such plans, including assumptions and standards specified in the PJM Manuals for estimates of expected load levels (prior to 2022/2023 Delivery Year) and estimates of peak load contribution (for the 2022/2023 Delivery Year and subsequent Delivery Years) as described in paragraph C. The PRD Plan shall explain and justify the methods used to determine the Nominal PRD Value. All assumptions and relevant variables affecting the Nominal PRD Value must be clearly stated. The PRD Plan must include sufficient data to allow a third party to audit the procedures and verify the Nominal PRD Value. Any non-compliance with a Nominal PRD Value for a prior Delivery Year shall be identified and taken into account. In addition, each submitted PRD Plan must include:

(i) documentation, in the form specified in the PJM Manuals, that the PRD Provider has in place contractual arrangements with the relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements, and adheres to PRD implementation standards specified in the PJM Manuals; in such cases, the PRD Provider shall provide the Office of the Interconnection copies of its applicable contracts with end-use customers (including any proposed contracts) within ten Business Days after a request for such contracts, or its PRD Plan shall be rejected;

(ii) prior to the 2022/2023 Delivery Year the expected peak load value that would apply, absent load reductions in response to price, to the end-use customer loads at a PRD Substation level, including applicable peak-load contribution data for such customers, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level. For the 2022/2023 Delivery Year and subsequent Delivery Years, estimates of Peak Load Contribution at a PRD Substation level, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iii) the Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year) or Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) of the identified load given the load's price-responsive characteristics, at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iv) Price-consumption curves ("PRD Curves") at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level that detail the base consumption level of the identified loads; and the decreasing consumption levels at increasing prices, provided that all identified load reductions must be capable of full implementation within 15 minutes of declaration of a Maximum Generation Emergency (prior to 2022/2023 Delivery Year) or Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) by the Office of the Interconnection, and provided further that the specified prices may not exceed the maximum energy offer price cap under the PJM Tariff and Operating Agreement;

(v) the estimated Nominal PRD Value of the Price Responsive Demand at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(vi) specifications of equipment used to satisfy the advanced metering and Supervisory Control criteria for eligible Price Responsive Demand, including a timeline and milestones demonstrating that such equipment shall be available and operational for the start of the relevant Delivery Year. Such equipment shall comply with applicable RERRA requirements and shall be designed to meet all PRD requirements, including, without limitation, meter reading requirements and Supervisory Control requirements, specified in the PJM Manuals. The PRD Provider shall demonstrate in the PRD Plan that the Supervisory Control equipment enables an automated load response by Price Responsive Demand to the price trigger; provided, however, that the PRD Provider may request in the PRD Plan an exception to the automation requirement for any individual registered end-use customer that is located at a single site and that has Supervisory Control over processes by which load reduction would be accomplished; and provided further that nothing herein relieves such end-use customer of the obligation to respond within 15 minutes to declaration of a Maximum Generation Emergency (prior to 2022/2023 Delivery Year) or a Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) in accordance with applicable PRD Curves. In addition to the above requirements and those in the PJM Manuals for metering equipment and associated data, metering equipment shall provide integrated hourly kWh values on an electric distribution company account basis and shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers). The installed metering equipment must be that used for retail electric service; or metering equipment owned by the end-use customer or PRD Provider that is approved by PJM and either read electronically by PJM or read by the customer or PRD Provider and forwarded to PJM, in either case in accordance with requirements set forth in the PJM Manuals; and

(vii) any RPM Auction clearing price below which the PRD Provider does not choose to commit PRD ("PRD Reservation Price"), specifying the relevant auction, Zone (or sub-Zonal LDA if applicable), and, if applicable, a range of up to ten pairs of PRD commitment levels and associated minimum RPM Auction clearing prices; provided however that the Office of the

Interconnection may interpolate PRD commitment levels based on clearing prices between prices specified by the PRD Provider.

E. Each PRD Provider that commits Price Responsive Demand through an accepted PRD Plan must, no later than one day before the tenth Business Day prior to the start of the Delivery Year for which such PRD is committed, register with PJM, in the form and manner specified in the PJM Manuals, sufficient PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment. All information required in the PRD Plan to be at a PRD Substation level if available at the time of submission of the PRD Plan that was not provided at the time of submission of such plan must be provided with the registration. The PRD Provider shall also identify in the registration each individual end-use customer with a peak load contribution of 10 kW or greater included in such Price Responsive Demand, the peak load contribution, Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year), and Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such customers. PJM shall provide notification of such PRD registrations to the applicable electric distribution company(ies). The PRD Provider shall maintain, and provide to the Office of the Interconnection upon request, an identification of all individual end-use customers with a peak load contribution of less than 10kW included in such Price Responsive Demand, and the peak load contribution, Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year), and Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) of such customers. The PRD Provider must maintain its PRD Substation-level registration of PRD-eligible load at the level of its Zonal (or sub-zonal LDA, if applicable) Nominal PRD Value commitment during each day of the Delivery Year for which such commitment was made. The PRD Provider may change the end-use customer registered to meet the PRD Provider's commitment during the Delivery Year, but such PRD Provider must always in the aggregate register sufficient Price Responsive Demand to meet or exceed the Zonal (or sub-Zonal LDA, if applicable) committed Nominal PRD Value level. A PRD Provider must timely notify the Office of the Interconnection, in accordance with the PJM Manuals, of all changes in PRD registrations. Such notification must remove from the PRD Provider's registration(s) any end-use customer load that no longer meets the eligibility criteria for PRD, effective as of the first day that such end-use customer load is no longer PRD-eligible.

F. Each PRD Provider shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Real-Time Energy Market. The most recent PRD Curve submitted by the PRD Provider in its PRD Plan or PRD registration shall be used for such purpose unless and until changed by the PRD Provider in accordance with the market rules of the Office of the Interconnection, provided that any changes to PRD Curves must be consistent with the PRD Provider's commitment of Price Responsive Demand hereunder.

G. The PRD Provider shall receive a Price Responsive Demand Credit for such registrations during the Delivery Year, in such Zone for such day, determined as follows:

PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling

Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].

For the 2022/2023 Delivery Year and subsequent Delivery Years, the factor equal to FZWNSP/FZPLDY is eliminated in the calculation of the LSE PRD Credit

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration .

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year;

And where the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone. A PRD Provider will receive a PRD Credit for each approved Price Responsive Demand registration that is effective on a given day. The total daily credit to a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day.

H. A PRD Provider may transfer all or part of its PRD commitment for a Delivery Year in a Zone (or sub-Zonal LDA) to another PRD Provider for its use in the same Zone or sub-Zonal LDA, through notice of such transfer provided by both the transferor and transferee PRD Providers to the Office of the Interconnection in the form and manner specified in the PJM Manuals. From and after the effective date of such transfer, and to the extent of such transfer, the transferor PRD Provider shall be relieved of its PRD commitment and credit requirements, shall not be liable for PRD compliance charges, and shall not be entitled to a Price Responsive Demand Credit; and the transferee PRD Provider, to the extent of such transfer, shall assume such PRD commitment, credit requirements, obligation for compliance charges and shall be entitled to a Price Responsive Demand Credit.

I. Any PRD Provider that commits Price Responsive Demand and does not register and maintain registration of sufficient PRD-eligible load, (including, without limitation, failing to install or maintain the required advanced metering or Supervisory Control facilities) in a Zone (or sub-Zonal LDA, if applicable) to satisfy in full its Nominal PRD Value commitment in such Zone (or sub-Zonal LDA) on each day of the Delivery Year for which such commitment is made shall be assessed a compliance charge for each day that the registered Price Responsive Demand is less than the committed Nominal PRD Value. Such daily penalty shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Weighted Final Zonal Capacity Price) or ($20/MW-day)]

Where: MW Shortfall = Daily Nominal PRD Value committed in such PRD Provider's PRD Plan (including any permitted amendment to such plan) for the relevant Zone or sub-Zonal LDA – Daily Nominal PRD Value as a result of PRD registration for such Zone or sub-Zonal LDA; and

Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction.

The MW Shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits, provided, however, that the PRD Provider may register additional PRD-eligible end-use customer load to satisfy its PRD commitment.

J. PRD Providers shall be responsible for verifying the performance of their PRD loads during each maximum emergency event (prior to the 2022/2023 Delivery Year) and Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) declared by the Office of the Interconnection. PRD Providers shall demonstrate that the identified PRD loads performed in accordance with the PRD Curves submitted at a PRD Substation level in the PRD Plan or PRD registration; provided, however, prior to the 2022/2023 Delivery Year, the previously submitted Maximum Emergency Service Level ("MESL") value shall be adjusted by a ratio equal to the amount by which the actual Zonal load during the declared event exceeded the PJM load forecast underlying the previously submitted MESL value. In accordance with procedures and deadlines specified in the PJM Manuals, the PRD Providers must submit actual customer load levels for all hours during the declared event and all other information reasonably required by the Office of the Interconnection to verify performance of the committed PRD loads.

K. Prior to the 2022/2023 Delivery Year, if the identified loads submitted for a Zone (or sub-Zonal LDA) by a PRD Provider exceed during any Emergency the aggregate MESL specified in all PRD registrations of such PRD Provider that have a PRD Curve specifying a price at or below the highest Real-time LMP recorded during such Emergency, the PRD Provider that committed such loads as Price Responsive Demand shall be assessed a compliance charge hereunder. The charge shall be based on the net performance during an Emergency of the loads that were identified as Price Responsive Demand for such Delivery Year in the PRD registrations submitted by such PRD Provider in each Zone (or sub-Zonal LDA, if applicable) and that specified a price at the MESL that is at or below the highest Real-Time LMP recorded during such Emergency. The compliance charge hereunder shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Final Zonal Capacity Price) or ($20/MW-day)] * 365 days

Where: MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA meeting the price condition specified above]

– {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone meeting the price condition specified above)]}.

For purposes of the above provision, the MW Shortfall for any portion of the Emergency event that is less than a full clock hour shall be treated as a shortfall for a full clock hour unless either: (i) the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification, regardless of the response rate submitted, or (ii) the hourly integrated value of the load was at or below the adjusted MESL. Such MW shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits; provided, however, that the performance and MW Shortfalls of all PRD-eligible load registered by the PRD Provider, including any additional or replacement load registered by such PRD Provider, provided that it meets the price condition specified above, shall be reflected in the calculation of the overall MW Shortfall. Any greater MW Shortfall during a subsequent Emergency for such Zone or sub-Zonal LDA during the same Delivery Year shall result in a further charge hereunder, limited to the additional increment of MW Shortfall. As appropriate, the MW Shortfall for non-compliance during an Emergency shall be adjusted downward to the extent such PRD Provider also was assessed a compliance penalty for failure to register sufficient PRD to satisfy its PRD commitment.

L. PRD Providers that register Price Responsive Demand shall be subject to test at least once per year to demonstrate the ability of the registered Price Responsive Demand to reduce to the specified Maximum Emergency Service Level prior to the 2022/2023 Delivery Year or the Firm Service Level for the 2022/2023 Delivery Year and subsequent Delivery Years, and such PRD Providers shall be assessed a compliance charge to the extent of failure by the registered Price Responsive Demand during such test to reduce to the relevant service level, in accordance with the following:

(i)

(a) Prior to the 2022/2023 Delivery Year, if the Office of the Interconnection does not declare during the relevant Delivery Year a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level is called during the relevant Delivery Year, then no compliance charges will be assessed hereunder.

(b) For the 2022/2023 Delivery Year, if the Office of the Interconnection does not declare an Emergency Action triggering a Performance Assessment Interval during the relevant Delivery Year or is not measured for compliance at a Performance Assessment Interval, then such registered PRD must demonstrate that it was tested for a one hour period between 10:00 AM EPT to 10:00 PM EPT during June through October or the following May of the relevant Delivery Year. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

(c) For the 2023/2024 Delivery Year and subsequent Delivery Years, if the registered PRD is not required to reduce the load for a Performance Assesment Interval during the relevant Delivery Year, then such registered PRD shall test for a two hour period between 11:00 EPT to 18:00 EPT on a weekday that is a non-NERC holiday during the relevant Delivery Year and in accordance with the following provisions. The Office of Interconnection shall schedule, on an alternating basis, one test during June through October or November through March for each Delivery Year that a test is required. The date and time of such test shall be selected by the Office of the Interconnection and notice of such test shall be provided to the PRD Provider in accordance with the procedure described in this section L.ii(b). If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

(ii)

(a) Prior to the 2023/2024 Delivery Year, all PRD registered in a Zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

(b) For the 2023/2024 Delivery Year and subsequent Delivery Years, all PRD registered in a zone will be tested simultaneously for two hours. The Office of the Interconnection may, at its discretion, cancel a test and retest to ensure system reliability.

If less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct re-tests limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

If 25 percent or more (by megawatts) of a PRD Provider's total PRD registered in a Zone fails the test the PRD Provider may request PJM to schedule a one-time retest limited to all registrations that failed the prior test, provided that all affiliated registrations must test simultaneously where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest can be conducted in May) and notice is provided consistent with the following procedure.

(c) Notification of the initial Office of the Interconnection scheduled test will be provided as follows:

On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date. The Office of the Interconnection will also notify the PRD Providers the test date. On test date, PRD Providers will receive start time through web service communications and as defined in the PJM Manuals.

Notification of any scheduled retest by the Office of the Interconnection will be provided as follows:

By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the PRD Providers the retest date. On retest date PRD Providers will receive start time through web service communications and as defined in the PJM Manuals.

(iii) A PRD Provider that registered PRD shall be assessed a PRD Test Failure Charge equal to the net PRD capability testing shortfall in a Zone during such test in the aggregate of all of such PRD Provider's registered PRD in such Zone times the PRD Test Failure Charge Rate. Prior to the 2022/2023 Delivery Year, the net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement:

MW Shortfall = [hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone]}.

The net PRD capability testing shortfall in such Zone shall be reduced by the PRD Provider's summer daily average of the MW shortfalls determined for compliance charge purposes under section I of this Schedule 6.1 in such Zone for such PRD Provider's registered PRD.

For the 2022/2023 Delivery Year and subsequent Delivery Years, the MW testing shortfall for a PRD registration is equal to the nominal load reduction value of such registration, capped at the daily Nominal PRD Value committed by such registration on the day of the test, minus the actual hourly load reduction for such registration. The test compliance results of the PRD Provider's registrations in a Zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall.

(iv) The PRD Test Failure Charge Rate shall equal such PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year, where the Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction.

M. The revenue collected from assessment of the charges assessed under subsections I, K, and L of this Schedule 6.1 shall be distributed on a pro-rata basis to all entities that committed Capacity Resources in the RPM Auctions for the Delivery Year for which the compliance charge is assessed, pro rata based on each such entity's revenues from Capacity Market Clearing Prices in such auctions, net of any compliance charges incurred by such entity.

N. For the 2022/2023 Delivery Year and subsequent Delivery Years, a PRD Provider is subject to a Non-Performance Assessment in accordance with the PJM Tariff, Attachment DD, section 10A. Compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval in same sub-Zone/Zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point at or below the Real-time LMP recorded during the Performance Assessment Interval. A PRD registration with an approved exception to the automation requirement will not have compliance measured during Performance Assessment Intervals that fall within the 15 minute response allowance. The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's peak load contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the peak load contribution. When five minute revenue meter data is not available to determine compliance of a PRD registration for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction for the hour ending that includes the Performance Assessment Interval(s) multiplied (twelve divided by the number of five minute intervals the PRD registration was to be measured for compliance). The actual load reduction for a registration for a Performance Assessment Interval is capped at the peak load contribution of the registration. If the PRD Provider fails to submit actual metered data for the registration for all hours during the day of a Performance Assessment Interval, the actual load reduction for such registration will be equal to zero MW.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.

B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

SCHEDULE 8

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party that has not elected the FRR Alternative for such Delivery Year shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR

Where:

OPL = Obligation Peak Load, defined asthe daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal RPM Scaling Factor = the factor determined as set forth in sections B and C of this Schedule

FPR = the Forecast Pool Requirement

Netting of Behind the Meter Generation for a Party with regard to Non-Retail Behind the Meter Generation shall be subject to the following limitation:

For the 2006/2007 Planning Period, 100 percent of the operating Non-Retail Behind the Meter Generation shall be netted, provided that the total amount of Non-Retail Behind the Meter Generation in the PJM Region does not exceed 1500 megawatts (“Non-Retail Threshold”). For each Planning Period/Delivery Year thereafter, the Non-Retail threshold shall be proportionately increased based on load growth in the PJM Region but shall not be greater than 3000 megawatts. Load growth shall be determined by the Office of the Interconnection based on the most recent forecasted weather-adjusted coincident summer peak for the PJM Region divided by the weather-adjusted coincident peak for the previous summer for the same area. After the load growth factor is applied, the Non-Retail Threshold will be rounded up or down to the nearest whole megawatt and the rounded number shall be the Non-Retail Threshold for the current Planning Period and the base amount for calculating the Non-Retail Threshold for the succeeding planning period. If the Non-Retail Threshold is exceeded, the amount of operating Non-Retail Behind the Meter Generation that a Party may net shall be adjusted according to the following formula:

Party Netting Credit = (NRT/ PJM NRBTMG) * Party Operating NRBTMG

Where: NRBTMG is Non-Retail Behind the Meter Generation

NRT is the Non-Retail Threshold

PJM NRBTMG is the total amount of Non-Retail Behind the Meter Generation in the PJM Region

The total amount of Non-Retail Behind the Meter Generation that is eligible for netting in the PJM Region is 3000 megawatts. Once this 3000 megawatt limit is reached, any additional Non-Retail Behind the Meter Generation which operates in the PJM Region will be ineligible for netting under this section.

In addition, the Party NRBTMG Netting Credit shall be adjusted pursuant to Schedule 16 of this Agreement, if applicable.

A Party shall be required to report to PJM such information as is required to facilitate the determination of its NRBTMG Netting Credit in accordance with the procedures set forth in the PJM Manuals.

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

For Delivery Years through May 31, 2018, Base Zonal Unforced Capacity Obligation = (ZWNSP * Base Zonal RPM Scaling Factor * FPR) + Zonal Short-Term Resource Procurement Target

For the 2018/2019 Delivery Year and subsequent Delivery Years, Base Zonal Unforced Capacity Obligation = (ZWNSP * Base Zonal RPM Scaling Factor * FPR)

and

Base Zonal RPM Scaling Factor = ZPLDY/ZWNSP x [RUCO / (RPLDY x FPR)]

Where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Delivery Year

ZWNSP = Zonal Weather-Normalized Summer Peak for the summer season concluding four years prior to the commencement of such Delivery Year

RUCO = the RTO Unforced Capacity Obligation satisfied in the Base Residual Auction for such Delivery Year.

RPLDY = RTO Preliminary Peak Load Forecast for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Updated RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to each of the First, Second, and Third Incremental Auctions for such Delivery Year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones.

C. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is decommitted in such auction. The Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year).

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Weather Normalized Summer Peak for such Zone to determine the Obligation Peak Load for each end-use customer within such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each Operating Day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. The Electric Distributor may submit corrections to the Obligation Peak Load data up to 12:00PM Eastern Prevailing Time of the next Business Day following the Operating Day.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a Zone must equal the Zonal Obligation Peak Load for such Zone.

SCHEDULE 8.1

FIXED RESOURCE REQUIREMENT ALTERNATIVE

The Fixed Resource Requirement (“FRR”) Alternative

A. The Fixed Resource Requirement (“FRR”) Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

B. Eligibility

1. A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources, Seasonal Capacity Performance Resources, and Base Capacity Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through the 2028/2029 Delivery Year.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and

quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include “slice of system” or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be

calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, an FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in $/MW-

day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource MWs that are committed to RPM for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any uncommitted Capacity Resource MWs for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Tariff, Attachment DD for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), subject to the limitations described in RAA, Schedule 8.1, section D, subsection D.2, or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to RAA, Schedule 8.1, section B, subsection B.2 that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party’s expected Daily Unforced Capacity Obligation under RAA, Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party’s total expected Unforced Capacity obligation (under both RAA, Schedule 8 and RAA, Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as:

> the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity’s FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Through the 2024/2025 Delivery Year, such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity’s Daily Unforced Capacity Obligation for such Zone times (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions). Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, such FRR Capacity Deficiency Charge shall equal the deficiency below such FRR Entity’s Daily Unforced Capacity Obligation for such Zone times the price level corresponding to Point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the Locational Deliverability Area encompassing the Zone of the FRR Entity.

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in

constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, however, through the 2024/2025 Delivery Year, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall pay a Locational Reliability Charge for the acquired load.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining the RTO/LDA Reliability Requirements, Limited Resource and Sub-Annual Constraints for the 2017/2018 Delivery Year, and Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the 2018/2019 and 2019/2020 Delivery Years in all future Incremental Auctions for such Delivery Years, and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

I. Savings Clause for State-Wide FRR Program

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and El05-148, the PJM Tariff and this Agreement. Each LSE subject to such state action shall become a Party to this Agreement and shall be deemed to have elected the FRR Alternative.

SCHEDULE 8.1 – Appendix
OHIO POWER COMPANY
FRR CAPACITY RATE

The Public Utilities Commission of Ohio (PUCO) in Case No. 10-2929-EL-UNC on July 2, 2012, issued an order approving a state compensation mechanism for load of alternative retail LSEs (a/k/a Competitive Retail Electric Service (CRES) providers) in Ohio Power Company's FRR Service Area for FRR capacity made available by Ohio Power Company under the RAA, effective as of August 8, 2012. For purposes of administering the state compensation mechanism, the wholesale rate shall be equal to the adjusted final zonal PJM RPM rate in effect for the rest of the RTO region for the current PJM delivery year, and with the rate changing annually on June 1, 2013, and June 1, 2014, to match the then current adjusted final zonal PJM RPM rate in the rest of the RTO region. The Final Zonal Capacity Price will be the price applicable to the unconstrained region of PJM adjusted for the RPM Scaling Factor, the Forecast Pool Requirement and Losses.

Schedule 8.1 – Appendix 2A

Appalachian Power Company (APCO)

CAPACITY COMPENSATION FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

The definitions and provisions contained in this Appendix 2A shall be applicable only to the provisions of Schedule 8.1 - Appendix 2A, unless otherwise specified.

"Capacity Rate" means the result produced by populating the Capacity Compensation Formula Rate Template with data to calculate the Fixed Resource Requirement capacity rate for load served by Virginia Competitive Service Providers ("CSPs").

"Annual Review Procedures" means the procedures pursuant to which an Interested Party may review the Annual Update and notify APCO of any specific challenges to the Annual Update.

"Annual Update" means the posting and informational filing submitted by APCO on or before May 25 of each year that sets forth the capacity rate for the subsequent Rate Year.

"Capacity Compensation Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Schedule 8.1 – Appendix 2B under Section D.8 of Schedule 8.1 of the PJM Interconnection, L.L.C. ("PJM") Reliability Assurance Agreement ("RAA").

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in APCO's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate template to be different from the result under the Formula Rate Template as calculated without such change.

"Partial Rate Year" means the period February 9, 2013 through May 31, 2013.

"Partial Rate Year Effective Date" means February 9, 2013.

"Protocols" means these Capacity Compensation Formula Rate Implementation Protocols.

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1 below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2 below.

Section 1 **<u>Annual Updates</u>**

a. The Capacity Rate for the Partial Rate Year shall become effective on the Partial Rate Year Effective Date and such Capacity Rate shall not be subject to the Protocols. Beginning June 1, 2013, the Capacity Rate shall be revised in accordance with the Capacity Compensation Formula Rate Template, and the Annual Update for the Rate Year beginning on June 1, 2013, and all subsequent Rate Years, shall be fully subject to the Protocols.

b. On or before May 25 of 2013 and each year thereafter, APCO shall recalculate its Capacity Rate, producing the Annual Update for the upcoming Rate Year, and shall post such Annual Update, in both PDF and working Excel spreadsheet versions, on PJM's Internet website. In addition, APCO shall submit such Annual Update as an informational filing with FERC. APCO will also post such Annual Update on APCO's Internet website at https://www.appalachianpower.com/service/choice/

c. The date as provided in Section 1.b shall be that Rate Year's Publication Date.

d. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

e. The Annual Update shall include a workable Excel file or files containing the data-populated Formula Rate Template as well as supporting calculations and workpapers that demonstrate and explain information not otherwise set out in APCO's FERC Form No. 1 reports. [1]

[1] It is the intent that each input to the Formula Rate Template will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet appurtenant to the filed Formula Rate Template, the inputs to the worksheet will meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate Template.

f. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate Template, be based upon prudently incurred costs; the data for such prudently incurred costs will be taken from APCO's FERC Form No. 1 for the most recent calendar year, and will be based upon the books and records of APCO (all of the foregoing data, books, and records maintained consistent with the USofA and FERC accounting policies, practices, and procedures);

(ii) Shall be populated, in accordance with FERC's orders establishing generally applicable ratemaking policies and the Formula Rate Template, with the data identified above;

(iii) Shall be subject to the Annual Review Procedures set forth in these Protocols; and

(iv) Shall disclose any change in accounting during the rate period that affects inputs to the formula rate or the resulting charges billed under the formula rate and, in particular, include the following:

(a) Disclose: (1) the initial implementation of an accounting standard or policy; (2) the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction; (3) corrections of errors and prior period adjustments; (4) the implementation of new estimation methods or policies that change prior estimates; and (5) changes to income tax elections.

(b) Identify items included in the formula rate at an amount other than on a historical cost basis, e.g., fair value adjustments.

(c) Identify any reorganization or merger transaction and explain the effect of the accounting for such transactions on inputs to the formula rate.

(d) To the extent these accounting changes and other matters affect APCO's inputs to its formula rate, APCO will provide a narrative explanation of how such changes affect those items on charges billed under the formula rate.

g. Formula Rate Inputs

(i) Stated inputs to the Formula Rate Template: rate of return on common equity; Post Employment Benefits other Than Pensions ("PBOPs"); and depreciation and amortization rates shall be stated values to be used in the

Formula Rate Template until changed pursuant to an FPA Section 205 or 206 filing.

(ii) Cost of Service elements recorded in accounts not specifically provided for in the Capacity Rate: any cost, expense or other element of the cost of providing service not specifically provided for shall not be recoverable under the Formula Rate until filed for pursuant to FPA Section 205, accepted by FERC and, if otherwise required, a determination has been made by the Office of the Chief Accountant regarding the journal entries for the transaction.

(iii) The Formula Rate Template refers to certain pages and line numbers found in APCO's FERC Form 1 used for reporting calendar year 2011 data. From time to time, FERC may make changes in the format of the FERC Form 1, and such changes may result in certain page and line references included in Formula Rate Template being rendered inaccurate. To the extent that only formatting changes are involved and there is no substantive change, the Formula Rate Template shall be interpreted as if the page and line references contained therein are references to the pages and lines contained in the current FERC Form 1 on which can be found the data described on the pages and lines of the prior FERC Form 1. Such changes in references shall be noted and new references stated in the formula and submitted to FERC in a limited Section 205 filing.

Section 2 <u>Annual Review Procedures</u>

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. No later than ten (10) days after the Publication Date, APCO will post the Annual Update on its website dedicated to Virginia Competitive Service Providers ("CSPs") and inform CSPs that they will have ten (10) days to request that APCO schedule an open meeting to discuss the Annual Update. If APCO receives one or more requests within such 10-day period, APCO will schedule an open meeting within thirty (30) days of such request(s). APCO shall provide at the meeting an item-by-item description of the major cost drivers for the change in rates, and an opportunity to discuss these items.

b. Interested Parties shall have up to one hundred ten (110) days after the Publication Date ("Review Period") (unless such period is extended with the written consent of APCO) to review the calculations and to notify APCO in writing of any specific challenges, including challenges related to any Material Changes, to the application of the Formula Rate in an Annual Update ("Preliminary Challenge").

c. Interested Parties shall have the right to serve reasonable information requests on APCO up to ninety (90) days after the Publication Date. Such information requests shall be limited to what is necessary to determine: (i) whether APCO has properly calculated the Annual Update under review (including any corrections pursuant to

Section 4); (ii) whether APCO has correctly applied the Formula Rate Template; (iii) whether the inputs to the Formula Rate Template are appropriate costs and revenue credits; and (iv) whether the inputs are just and reasonable. Interested Persons can make information requests regarding allocation methodologies, including inter-corporate cost allocation methodologies, used to derive the inputs. Interested Parties may request accounting practices to the extent they impact the determination of the annual revenue requirement. They may also request information on procurement methods and cost control methodologies used by APCO.

d. APCO shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by APCO up to seventy-five (75) days after the Publication Date for which APCO is unable to provide a response before the end of the Review Period, the Review Period shall be extended day-for-day until APCO's response is provided.

e. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Annual Update. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update, but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such challenge affects the subsequent Annual Update.

f. In any proceeding initiated to address a Preliminary or Formal Challenge or sua sponte by FERC, a party or parties seeking to modify the Formula Rate Template in any respect shall bear the applicable burden under the Federal Power Act ("FPA"). Nothing in the protocols changes the burden of proof imposed under the FPA.

Section 3 <u>Resolution of Challenges</u>

a. If APCO and any Interested Parties have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period ends, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of APCO to continue efforts to resolve the Preliminary Challenge) to submit a written Formal Challenge to FERC, pursuant to 18 C.F.R. § 385.206, which shall be served on APCO by electronic service on the date of such filing ("Formal Challenge"). However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if FERC already has initiated a proceeding to consider the Annual Update.

b. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify APCO of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issue in a Preliminary Challenge or Formal Challenge.

c. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before any court to review a FERC decision.

d. Any response by APCO to a Formal Challenge must be submitted to FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party or parties by electronic service on the date of such filing.

e. APCO shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate Template, and the applicable procedures in these Protocols, and of proving that it has properly calculated the challenged Annual Update pursuant to the Formula Rate Template, and of proving it has reasonably adopted and applied any Material Changes in that year's Annual Update.

f. These Protocols in no way limit the rights of APCO or any Interested Party to initiate a proceeding at FERC at any time with respect to the Formula Rate Template or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and FERC's regulations.

g. It is recognized that resolution of Formal Challenges concerning Material Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update, or changes to the Formula Rate Template to ensure that the Formula Rate Template continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 4 <u>Changes to Annual Informational Filings</u>

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of APCO, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, or as the result of any FERC proceeding to consider a prior year's Annual Update, APCO shall promptly notify the Interested Parties, file a correction to the Annual Update with FERC as an amended informational filing describing the change(s) and the cost impact.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by APCO and the Interested Parties, a correction made under Section 4.a prior to the time determined for the filing of a Formal Challenge shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Parties to review the Annual Update, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the review of the Annual Update shall then be limited to the aspects of the Formula Rate Template affected by the corrections.

Schedule 8.1 – Appendix 2B
Appalachian Power Company
Capacity Compensation Formula Rate

Appendix 2
Page 1

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CAPACITY RATE
12 Months Ending 12/31/####

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

Note A: Rate will be applied to peak obligation demands at or adjusted to generation level (including losses).

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DETERMINATION OF CAPACITY RATE
12 Months Ending 12/31/####

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(APCo 5 CP Demand/365) (Note A)}}$$

$$\frac{\$}{\#\qquad /365} = \$$$

Where: Annual Production Fixed Cost, P.4, L.8.

Note A: Average of demand at time of PJM five highest daily peaks. – See Workpaper 1.

Appendix 2
Page 3

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/####

		Reference (1)	Production Amount (2)
1.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	Note B	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: See Workpaper 16
Note B: See Workpaper 17

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/####

		Reference (1)	PRODUCTION Amount (2)
1.	Return on Rate Base	P.5, L.18, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.9, Col.(2); Note A	$
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(3)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale	Note B	$
7.	Sales for Resale (Energy Credit)	Note C	$
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

Note A: See page 20 for depreciation rates by plant account.

Note B: Capacity related revenues associated with sales as reported in Account 447 (includes pool capacity demand). See Workpaper 15d.

Note C: Workpaper 15d

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)-(4)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)-(4)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)-(4)	$	$	$
6.	Plant Held for Future Use (Note A)	FF1, P.214	$	$	$
7.	Subtotal - Electric Plant	L.4 - L.5 + L.6	$	$	$
	WORKING CAPITAL				
8.	Materials & Supplies				
9.	Fuel	P.9, L.2, Col.(2)-(4)	$	$	$
10.	Nonfuel	P.9, L.8, Col.(2)-(4)	$	$	$
11.	Total M & S	L.9 + L.10	$	$	$
12.	Prepayments Nonlabor (Note B)		$	$	$
13.	Prepayments Labor (Note B)		$	$	$
14.	Prepayments Total (Note B)	L.12 + L.13	$	$	$
15.	Cash Working Capital	P.8, L.7, Col.(1)-(3)	$	$	$
16.	Total Rate Base	L.7 + L.11 + L.14 + L.15	$	$	$
17.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
18.	Return on Rate Base	L.16 x L.17	$	$	$

Note A: Workpaper 19

Note B: WP-5c Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/####

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	Line 16	$	Line 16	$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3)-(5), L.25	$	$	$
4.	Total	L.2 + L.3	$		$	$	$
		Note A				%	%
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.	General & Intangible Plant Allocator		%	L.5/L.6	%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)	Line 20	$	Line 20	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
12.	ACCUMULATED DEFERRED TAXES (Note A)	(Note E)	$	P.6a, L.52	$	$	$

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.
Note E: WP8a, WP8ai

GSU DETAILS (Lns 2 and 9 above)

					PRODUCTION		
		Reference	Amounts (1)	Reference	Amount (2)	Demand(3)	Energy (4)
13.	GROSS PLANT IN SERVICE						
14.	Plant in Service (Note C)	WP6a. L.11	$	WP6a. L.11	$	$	$
15.	GUS Plant in Service (Note C)	P.3 L.1, Col (2)			$	$	$
16.	Total Plant in Service (Note C_	L.14 + L.15			$	$	$
17.	ACCUMULATED PROVISION FOR DEPRECIATION						
18.	Accumulated Prov. For Depreciations (Note D)	WP6b, L.7	$	WP6b	$	$	$
19.	GSU Accumulated Prov. Depreciation (Note D)	WP16			$	$	$
20	Total Accumulated Depreciation (Note D)	L.18 + L.19			$	$	$

APPALACHIAN POWER COMPANY
BLANK FORMUAL RATE TEMPLATE
PRODUCTION RELATED ADIT
12 Months Ending 12/31/####

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1.	190	Excluded Items	$	$			
2.	190	100% Production (Energy)	$		$		
3.	190	100% Production (Demand)	$			$	
4.	190	Labor Related	$				$
5.	190	Total	$	$	$	$	$
6.		Production Allocation		%	%	%	%
7.		(Gross Plant or Wages/Salaries)		$	$	$	$
8.		Demand Related			$	$	$
9.		Energy Related			$	$	$
10.		Note A			Direct	Direct	P.7, Note B
11.	281	Excluded Items	$	$			
12.	281	100% Production (Energy)	$		$		
13.	281	100% Production (Demand)	$			$	
14.	281	Labor Related	$				$
15.	281	Total	$	$	$	$	$
16.		Production Allocation		%	%	%	%
17.		(Gross Plant or Wages/Salaries)		$	$	$	$
18.		Demand Related			$	$	$
19.		Energy Related			$	$	$
20.		Allocation Basis			Direct	Direct	P.7, Note B
21.	282	Excluded Items	$	$			
22.	282	100% Production (Energy)	$		$		
23.	282	100% Production (Demand)	$			$	
24.	282	Labor Related	$				$
25.	282	Total	$	$	$	$	$
26.		Production Allocation		%	%	%	%
27.		(Gross Plant or Wages/Salaries)		$	$	$	$
28.		Demand Related			$	$	$
29.		Energy Related			$	$	$
30.		Allocation Basis			Direct	Direct	P.7, Note B
31.	283	Excluded Items	$	$			
32.	283	100% Production (Energy)	$		$		
33.	283	100% Production (Demand)	$			$	
34.	283	Labor Related	$				$
35.	283	Total	$	$	$	$	$
36.	283	Production Allocation		%	%	%	%
37.		(Gross Plant or Wages/Salaries)		$	$	$	$
38.		Demand Related			$	$	$
39.		Energy Related			$	$	$
40.		Allocation Basis			Direct	Direct	P.7, Note B
41.	255	Excluded Items	$	$			
42.	255	100% Production (Energy)	$		$		
43.	255	100% Production (Demand)	$			$	
44.	255	Labor Related	$				$
45.	255	Total	$	$	$	$	$
46.	255	Production Allocation		%	%	%	%
47.		(Gross Plant or Wages/Salaries)		$	$	$	$

	Summary Production Related ADIT	Total	Demand	Energy
48.	Summary Production Related ADIT	Total	Demand	Energy
49.	P Plant (Energy Related)	$	$	$
50.	P Plant (Demand Related)	$	$	$
51.	Labor Related	$	$	$
52	Total	$	$	$

Source: Functionalized balances for Accounts 190, 281, 282, 283 and 255 from WP-8a and 8ai.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/####

	Total System (Note A)	Allocation Factor	General Plant Accounts 101 and 106 Related to Production (1) x (2)	Demand	Energy	FERC Form 1 Reference
1. GENERAL PLANT	(1)	(2)	(3)	(4)	(5)	
2						
3. Land	$	Note B	$	$	$	
4. General Offices	$		$	$	$	
5. Total Land	$		$	$	$	P207 L86 Col (g)
6		%				
7. Structures	$	Note B	$	$	$	
8. General Offices	$		$	$	$	
9. Total Structures	$		$	$	$	P207 L87 Col (g)
10		%				
11. Office Equipment	$	Note B	$	$	$	
12. General Offices			$	$	$	
13. Total Office Equipment	$		$	$	$	P207 L88 Col (g)
14. Transportation Equipment	$	Note B	$	$	$	P207 L89 Col (g)
15. Stores Equipment	$	Note B	$	$	$	P207 L90 Col (g)
16. Tools, Shop & Garage Equipment	$	Note B	$	$	$	P207 L91& L93 Col (g)
17. Lab Equipment	$	Note B	$	$	$	P207 L92 Col (g)
18. Communications Equipment	$	Note B	$	$	$	P207 L94 Col (g)
19. Miscellaneous Equipment	$	Note B	$	$	$	P207 L95 Col (g)
20. Subtotal General Plant	$		$	$	$	P207 L96 Col (g)
21. PERCENT		Note C	%	%	%	
22. Other Tangible Property		Note D	$	$	$	P207 L97 Col (g)
23. TOTAL GENERAL PLANT	$		$	$	$	
24. INTANGIBLE PLANT	$	Note B	$	$	$	P205 L5 Col (g)
25. TOTAL GENERAL AND INTANGIBLE	$		$	$	$	L23 + L.24
26. PERCENT		Note E	%	%	%	

NOTE A: See Workpaper 6c.

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20. (see WP-9a)	$
c. Ratio (b / a)	%

NOTE C: L.20, Col.(3) / L.20, Col.(1)

NOTE D: Directly assigned to Production

NOTE E: L.28, Col.(3) / L.28, Col.(1)

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/####

	Reference	PRODUCTION Amount (1)	Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12 Col.(1)-(3)	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru L.3,Col. (1)-(3)	$	$	$
3. Less Purchased Power	P.14, L.11, Col.(1)-(3)	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17, Col.(3)-(5)	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/####

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel (Note C)	FF1, P.110, L.,45,46 Workpapers WP-5b	$		$	$	$
3. Non-Fuel						
4. Production	Note D	$	100% Col. 1	$	$	$
5. Transmission		$	0	$	$	$
6. Distribution		$	0	$	$	$
7. General		$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$
9. Account 158 Allowances	Note D	$		$	$	$

Note A: Year end balance
Note B: Column (1) times % from P.7, Col.(3), L.26.
Note C: See Workpaper 5b.
Note D: See Workpaper 5a.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/####

		Account	Reference	System Amount (1)	Alllocation Factor % (2)	Production Amount (3)	Demand (4)	Energy (5)	FERC Form 1 Reference
1.	ADMINISTRATIVE & GENERAL EXPENSE								
2.	RELATED TO WAGES AND SALARIES								
3.	A&G Salaries	920	WP 10a	$					P323 L181 Col (b)
4.	Outside Services	923	WP 10a	$					P323 L 184 Col (b)
5.	Employee Pensions & Benefits	926	WP 10a	$	Note F				P323 L187 Col (b)
6.	Office Supplies	921	WP 10a	$					P323 L182 Col (b)
7.	Injuries & Damages	925	WP 10a	$					P323 L186 Col (b)
8.	Franchise Requirements	927	WP 10a	$					P323 L188 Col (b)
9.	Duplicate Charges - Cr.	929	WP 10a	$					P323 L190 Col (b)
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$	
11.	Miscellaneous General Expense	930	WP 10a	$	Note A, C & D	$	$	$	P323 L192 Col (b)
12.	Adm. Expense Transfer – CR	922	WP 10a	$	Note B	$	$	$	P323 L183 Col (b)
13.	Property Insurance	924	WP 10a	$	Note E	$	$	$	P323 L185 Col (b)
14.	Regulatory Comm. Expenses	928	WP 10a	$	Note C	$	$	$	P323 L189 Col (b)
15.	Rents	931	WP 10a	$	Note B	$	$	$	P323 L193 Col (b)
16.	Maintenance of General Plant	935	WP 10a	$	Note B	$	$	$	P323 L196 Col (b)
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$	

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.26
Note C: See Workpaper 11. Excludes all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: PBOP expense is fixed at $6,222,780. This amount cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/####

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Reference	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
1.	Long Term Debt	Note A	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	10.4%	%
4.	Total	L1 + L2 + L3	$	%			%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.4 Col. (2).

Note C: P.13b, L.5.Col (2)

Note D: P.12, L.16, Col. (2).

Note E: P.13a. L.4, Col (2)

Note F: Return on equity cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT
12 Months Ending 12/31/####

		Reference	Debt Balance	Interest & Cost Booked
			(1)	(2)
	12 Months Ending 12/31/2009 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.	Note A	$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	Workpaper-13, L.7	Note A	$
12.	Sub-total Costs and Expense			$
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 11, Col. (6)		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 15, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L. 5, Col.(1)			%

Note A: Reconciliation of Interest Expense to FF1, pg 257, Ln 33 Col (1)

Ln 6 Interest Expense (Acc 427)	$
Ln 11 Interest on LTD Assoc Companies (portion Acc 430)	$
FF1, pg 257, Ln 33 Col (i)	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/####

		(1)	(2)	(3)	(4)	(5)	(6)
				Net Includable			
	HEDGE AMT BY ISSUANCE	Total Hedge	Excludable	Hedge Amount	Unamortized	Amortization Period	
	FERC Form 1, p. 256-257 (i)	(Gain) / Loss	Amounts (Note A)	Subject to Limit	Balance	Beginning	Ending
1.	Debt Issuance #1	$	$	$	$		
2.	Debt Issuance #2	$	$	$	$		
3.	Debt Issuance #3	$	$	$	$		
4.	Total Hedge Amortization	$	$	$			
	Limit on Hedging (G)/L on Interest Rate Derivatives of LTD						
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit						%
	Enter a hedge Gain as a negative value and a hedge Loss as a positive value						
6.	Total Capitalization			Page11, L.4, col.(1)		$	
7.	5 basis point Limit on (G)/L Recovery						#
8.	Amount of (G)/L Recovery Limit			L. 12 * L.13			$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)						$
	To be subtracted or added to actual Interest Expenses on Page 12, Line 14						

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of capital to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded above.

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PREFERRED STOCK
12 Months Ending 12/31/####

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 9 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Total Preferred Stock		L.2 + L.3	$
5.	Average Cost Rate		L.1 / L.4	%

Note A: Workpaper -12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock.

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMMON EQUITY
12 Months Ending 12/31/####

		(1) Source	(2) Balances
1.	Total Proprietary Capital	WP-12a,L. 1 col. a	$
	Less:		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, L 1 col.b+c+d	$
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, L.1, col.e	$
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, L.1, col.f	$
5.	Total Balance of Common Equity	L.1-2-3-4	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/####

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)	FERC Form 1 Reference
1. Coal Handling	501.xx	$	$	$	P320 L5 Col (b) [Note D]
2. Lignite Handling	501.xx	$	$	$	P320 L5 Col (b) [Note D]
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$	$	$	P320 L5 Col (b) [Note D]
4. Rents	507	$	$	$	P320 L11 Col (b)
5. Hydro O & M Expenses	535-545	$	$	$	P320 L.44-L.49 Col (b) P320 L.53-L.57 Col (b)
6. Other Production Expenses	557	$	$	$	P321, L.78 Col (b)
7. System Control of Load Dispatching	Note C	$	$	$	P321, L77., L88., L92., P322, L.121, Col (b)
8. Other Steam Expenses	Note A	$	$	$	
9. Combustion Turbine	Note A	$	$	$	
10. Nuclear Power Expense-Other	Note A	$	$	$	
11. Purchased Power	555	$	$	$	P321 L76 Col (b)
12. Total Production Expense Excluding Fuel Used In Electric Generation above	Sum of L.1 – L.11	$	$	$	
13. A & G Expense P.10, L.17		$	$	$	
14. Generator Step Up related O&M	Note B	$	$	$	
15. Total O & M		$	$	$	

NOTE A: Amounts recorded in O&M Expense Accounts classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8, and 575.7.

NOTE D: Subaccount details of FF1 Accounts from Company's books and records

Reconciliation of System Control of Load Dispatching	
System Control and Load Dispatching	$
Scheduling, System Control	$
Reliability Planning and Standards Dev	$
Market Facilitation, Monitoring and Compliance	$
Ln 7, Pg 14	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

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Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	Xx
4	Fuel	501	Xx	-
5	Steam expenses	502	-	Xx
6	Steam from other sources	503	Xx	-
7	Steam transferred-Cr.	504	Xx	-
8	Electric expenses	505	-	Xx
9	Miscellaneous steam power expenses	506	-	Xx
10	Rents	507	-	Xx
11	Allowances	509	Xx	-
12	Maintenance supervision and engineering	510	Xx	-
13	Maintenance of structures	511	-	Xx
14	Maintenance of boiler plant	512	Xx	-
15	Maintenance of electric plant	513	Xx	-
16	Maintenance of miscellaneous steam plant	514	-	Xx
17	Total steam power generation expenses			
18	Nuclear Power			
19	Operation supervision and engineering	517		Xx
20	Coolants and Water	519		Xx
21	Steam Expenses	520		Xx
22	Steam from other sources	521		Xx
23	Less: ; Steam Transferred	522		Xx
24	Electric Expenses	523		Xx
25	Miscellaneous Nuclear Power Expense	524		Xx
26	Rents	525		Xx
27	Maintenance supervision and engineering	528	Xx	
28	Maintenance of structures	529		Xx
29	Maintenance of Reactor Plant Equip	530	Xx	
30	Maintenance of electric plant	531	Xx	
31	Maintenance of Misc Nuclear Plant	532	Xx	
32	Total power production expenses Nuclear			
33	Hydraulic Power Generation			
34	Operation supervision and engineering	535	-	Xx
35	Water for power	536	-	Xx
36	Hydraulic expenses	537	-	Xx
37	Electric expenses	538	-	Xx
38	Misc. hydraulic power generation expenses	539	-	Xx
39	Rents	540	-	Xx
40	Maintenance supervision and engineering	541	-	Xx
41	Maintenance of structures	542	-	Xx
42	Maintenance of reservoirs, dams and waterways	543	-	xx
43	Maintenance of electric plant	544	Xx	-
44	Maintenance of miscellaneous hydraulic plant	545	-	xx
45	Total hydraulic power generation expenses			
46	Other Power Generation			
47	Operation supervision and engineering	546	-	xx

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Line No.	Description	FERC Account No.	Energy Related	Demand Related
48	Fuel	547	Xx	-
49	Generation expenses	548	-	Xx
50	Miscellaneous other power generation expenses	549	-	xx
51	Rents	550	-	xx
52	Maintenance supervision and engineering	551	-	xx
53	Maintenance of structures	552	-	xx
54	Maintenance of generation and electric plant	553	-	xx
55	Maintenance of misc. other power generation plant	554	-	xx
56	Total other power generation expenses			
57	Other Power Supply Expenses			
58	Purchased power	555	Xx	xx
59	System control and load dispatching	556	-	xx
60	Other expenses	557	-	xx
61	Station equipment operation expense (Note A)	562	-	xx
62	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses. See Note D, Page 6

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/####

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
	Depreciation and Amortization			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro – Conventional	$	$	$
4.	Hydro – Pump Storage l	$	$	$
5.	Int. Comb.	$	$	$
6.	Other Production	$	$	$
7.	Generator Step Up Related Depreciation (Note A)	$	$	$
8.	Production Related General & Intangible Plant (Note B)	$	$	$
9.	Total Production	$	$	$

Note: Lines 1 through 6 will be Depreciation Expense reported on P.336 of the
FF1 excluding the amortization of acquisition adjustments. See Workpaper 6d.

Line 8 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for
amortization adjustments) times ratio of Production Related General
Plant to total General Plant computed on P.7, L. 26, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 7 , see P.3, L.5

Note B:

A	Production Related General & Intangible Plant		
B	General Plant	WP 6d	$
C	Intangible Plant	WP 6d	$
D	Total General & Intangible Plant	Ln. b + Ln. c	$

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E	Production Demand Labor Allocator	Pg. 7, Ln. 26	%
F	Production Demand Related General & Intangible	Ln. d x Ln. e	$
G	Production Energy Labor Allocator	Pg. 7, Ln. 26	%
H	Production Energy Related General & Intangible	Ln. d x Ln. g	$
I	Total Production Related General & Intangible Plant	Ln. f + Ln. h	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RPODUCTION RELATED TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/####

		SYSTEM		.	PRODUCTION
		REFERENCE	AMOUNT	%	AMOUNT
			(1)	(2)	(3)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production	Note A	$		$
5	Gross Receipts / Distribution Related	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

Note A: See Workpaper 8c.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	$	%
(2) Production W & S	$	%

Note C: Allocated on the basis of Gross Plant Investment from Schedule P. 6, Ln.7

Note D: Not allocated to wholesale

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.18	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/####

		(1) Source	(2) Rates & Amounts
1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * P)} =		%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
3.	where WCLTD from P.11 L.1, Col (4) and WACC from P.11 L.,4, Col. (4) and FIT, SIT & P as shown below.		
4.	GRCF=1 / (1 - T)		#
5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	P (Note A)	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization	L.10 x L.11	$
13.	ITC Adjustment	L.12 x L.4	$
14.	Gross Plant Allocator		Total
15.	Gross Plant	P.6, L.4, Col.1	$
16.	Production Plant Gross	P.6, L.5, Col.2	$
17.	Demand Related Production Plant	P.6, L.5, Col.3	$
18.	Energy Related Production Plant	P.6, L.5, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

Note A: Percent deductible for state purposes provided from Company’s books and records.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DEPRECIATION RATES
EFFECTIVE JUNE 1, 2015

Note: APCO will not change the depreciation or amortization rates shown on this page of the template absent a Section 205 or Section 206 filing.

STEAM PRODUCTION PLANT

Mountaineer Plant

311.0	Structures and Improvements	2.44%
312.0	Boiler Plant Equipment	2.75%
312.0	Boiler Plant Equipment – SCR Catalyst	6.99%
314.0	Turbogenerator Units	2.28%
315.0	Accessory Electric Equipment	1.80%
316.0	Misc. Power Plant Equipment	2.21%

Kanawha River Plant

311.0	Structures and Improvements	Retired
312.0	Boiler Plant Equipment	Retired
314.0	Turbogenerator Units	Retired
315.0	Accessory Electric Equipment	Retired
316.0	Misc. Power Plant Equipment	Retired

Amos Plant - Units 1 & 2

311.0	Structures and Improvements	2.03%
312.0	Boiler Plant Equipment	3.29%
312.0	Boiler Plant Equipment – SCR Catalyst	6.01%
314.0	Turbogenerator Units	3.32%
315.0	Accessory Electric Equipment	2.79%
316.0	Misc. Power Plant Equipment	3.10%

Amos Plant - Unit 3

311.0	Structures and Improvements	2.54%
312.0	Boiler Plant Equipment	3.56%
312.0	Boiler Plant Equipment – SCR Catalyst	7.63%
314.0	Turbogenerator Units	3.12%
315.0	Accessory Electric Equipment	2.17%
316.0	Misc. Power Plant Equipment	2.68%

Sporn Plant

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Clinch River Plant

311.0 Structures and Improvements	3.86%
312.0 Boiler Plant Equipment	4.73%
314.0 Turbogenerator Units	3.68%
315.0 Accessory Power Equipment	4.37%
316.0 Misc Power Plant Equipment	7.11%

Glen Lyn Plant #5

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Glen Lyn Plant #6 and Common

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Putnam Coal Terminal

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Central Plant Maintenance	316.0 Misc Power Plant Equipment	2.51%
Central Machine Shop	316.0 Misc Power Plant Equipment	2.70%
Little Broad Run - Mountaineer	311.0 Structures and Improvements	3.34%
	312.0 Boiler Plant Equipment	3.24%
	315.0 Accessory Electric Equipment	3.41%

HYDRAULIC PRODUCTION PLANT

Claytor		
	331.0 Structures and Improvements	1.65%
	332.0 Reservoirs, Dams, Waterways	1.10%
	333.0 Waterwheels, Generators, Turbines	1.08%
	334.0 Accessory Plant Equipment	2.16%
	335.0 Misc Power Plant Equip	2.61%
	336.0 Roads, Railroads, Bridges	0.71%
Byllesby		
	331.0 Structures and Improvements	5.54%
	332.0 Reservoirs, Dams, Waterways	6.82%
	333.0 Waterwheels, Generators, Turbines	5.93%
	334.0 Accessory Plant Equipment	4.14%
	335.0 Misc Power Plant Equip	6.73%
Buck		
	331.0 Structures and Improvements	4.49%
	332.0 Reservoirs, Dams, Waterways	4.94%
	333.0 Waterwheels, Generators, Turbines	4.10%
	334.0 Accessory Plant Equipment	4.60%
	335.0 Misc Power Plant Equip	5.84%
	336.0 Roads, Railroads, Bridges	4.72%

Niagara

331.0	Structures and Improvements	2.58%
332.0	Reservoirs, Dams, Waterways	5.09%
333.0	Waterwheels, Generators, Turbines	4.00%
334.0	Accessory Plant Equipment	4.89%
335.0	Misc Power Plant Equip	4.83%

Reusens

331.0	Structures and Improvements	5.66%
332.0	Reservoirs, Dams, Waterways	5.77%
333.0	Waterwheels, Generators, Turbines	6.04%
334.0	Accessory Plant Equipment	5.04%
335.0	Misc Power Plant Equip	6.61%

Leesville

331.0	Structures and Improvements	1.04%
332.0	Reservoirs, Dams, Waterways	1.66%
333.0	Waterwheels, Generators, Turbines	1.33%
334.0	Accessory Plant Equipment	2.09%
335.0	Misc Power Plant Equip	2.12%
336.0	Roads, Railroads, Bridges	0.93%

London

331.0	Structures and Improvements	2.61%
332.0	Reservoirs, Dams, Waterways	2.40%
333.0	Waterwheels, Generators, Turbines	2.72%
334.0	Accessory Plant Equipment	2.59%
335.0	Misc Power Plant Equip	2.80%
336.0	Roads, Railroads, Bridges	1.68%

Marmet

331.0	Structures and Improvements	2.08%
332.0	Reservoirs, Dams, Waterways	2.73%
333.0	Waterwheels, Generators, Turbines	2.84%
334.0	Accessory Plant Equipment	2.62%
335.0	Misc Power Plant Equip	2.73%
336.0	Roads, Railroads, Bridges	1.71%

Winfield

331.0	Structures and Improvements	2.32%
332.0	Reservoirs, Dams, Waterways	2.14%
333.0	Waterwheels, Generators, Turbines	2.46%
334.0	Accessory Plant Equipment	2.40%
335.0	Misc Power Plant Equip	2.26%
336.0	Roads, Railroads, Bridges	2.44%

Smith Mountain

331.0	Structures and Improvements	1.31%
332.0	Reservoirs, Dams, Waterways	1.22%
333.0	Waterwheels, Generators, Turbines	2.24%
334.0	Accessory Plant Equipment	2.45%
335.0	Misc Power Plant Equip	2.67%
336.0	Roads, Railroads, Bridges	1.09%

OTHER PRODUCTION PLANT

Ceredo

341.0	Structures and Improvements	1.33%
344.0	Generators	1.44%
345.0	Accessory Electrical Equip.	1.35%
346.0	Misc Power Plant Equipment	2.84%

Dresden

341.0	Structures and Improvements	2.87%
342.0	Fuel Holders, Producers,and Acessories	2.88%
344.0	Generators	2.87%
345.0	Accessory Electrical Equip.	2.89%
346.0	Misc Power Plant Equipment	3.49%

GENERAL PLANT

390.0	Structures and Improvements	1.51%
391.0	Office Furniture and Fixtures	2.89%
392.0	Transportation Equipment	1.82%
393.0	Stores Equipment	1.76%
394.0	Tools, Shop & Garage Equip.	2.36%
395.0	Laboratory Equipment	2.65%
396.0	Power Operated Equipment	1.91%
397.0	Communications Equipment	4.06%
398.0	Misc Equipment	2.62%

INTANGIBLE PLANT

301.0	Organization	0.00%
302.0	Franchises & Consents	End of Life
303.0	Misc Intangible Plant	20.00%

Schedule 8.1 – Appendix 2C
Appalachian Power Company
Workpapers in Support of the Capacity Compensation Formula Rate

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 1 - Production System Peak Demand
For the Year Ending December 31, _ _ _ _

Month	Day	(EDT) Hour	Demand (MW)	Source
July	#	#	#	CBR[1]
July	#	#	#	
July	#	#	#	
July	#	#	#	
June	#	#	#	
Average Peak			#	
Average Production System Peak Demand			#	

Company's average five CP demands at time of PJM system peak.

Notes:
[1]CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 2 - Production Revenue Credits
For the Year Ending December 31, _ _ _ _

	Production			Source 1
	Total	Demand	Energy	CBR[1]
	$	$	$	
Total	$	$	$	

Notes:

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 3

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 4

Intentionally left blank - not applicable.

Appalachian Power Company

Capacity Cost of Service Formula Rate
Workpaper 5a - Materials and Supplies
Balances as of December 31, _ _ _ _

Period	Function	1540001 M&S Regular	1540004 M&S Exempt Material	1540006 Lime and Limestone	1540012 Urea Charge	1540013 Transportation Inventory	1540022 M&S Lime & Limestone Intrasit	1540023 M&S Urea	1540024 M&S Proj Spares	M&S Total	Source [1]
12/31/20##	Production	$	$	$	$	$	$	$	$	$	110.48.c
	Transmission	$	$	$	$	$	$	$	$	$	
	Distribution	$	$	$	$	$	$	$	$	$	
									Total	$	

Period	Function	158 Allowances	Source [1]
12/31/20##	Production	$	110.52.c
	Transmission	$	
	Distribution	$	

M&S December 20##[2]		
Production	$	%
Transmission	$	%
Distribution	$	%
	$	%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5b - Fuel Inventory
Balances as of December 31, _ _ _ _

Period	1510001 Fuel Stock Coal	1510002 Fuel Stock Oil	1510003 Fuel Stock Gas	1510004 Fuel Stock Coal Trans	1510019 Fuel Stock Prepays	1510020 Fuel Stock In Transit	Fuel Stock Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	110.45.c

Period	1520000 Fuel Stock Undistributed	Source [1]
12/1/20##	$	110.46.c

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5c – Prepayments
For the Year Ending December 31, _ _ _ _

Period	1650001 Prepayments Insurance	1650004 Prepayments Rents	1650005 Prepayments Employee Benefits	1650006 Prepayments Other	1650009 Prepayments Carrying Cost	1650021/ 1650023 Prepayments Ins. & Lease	165000211* Prepayments Taxes	Prepayments Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	$	111.57.c

Period	Exclude [2] Rate Base	Non Labor [2] Related	Labor [2] Related
12/1/20##	$	$	$

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

1650001 - This account shall include amounts representing prepayments of insurance.
1650004 - This account shall include amounts representing prepayments of interest.
1650005 - This account shall include amounts representing prepayments of employee benefits.
1650006 - This account shall include amounts representing prepayments of other items not listed.
1650009 - This account is used for factoring the AEP-East electric accounts receivable.

1650021 - This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
1650023 - Track balance of prepaid lease expense for agreements that qualify as a lease under company policy and are not tracked in PowerPlant Lease Accounting system will use this account.

165000211 - This account shall include amounts representing prepayments of taxes.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6a - Plant in Service
Balances as of December 31, _ _ _ _

Line	Month	Production					
		Total		ARO			Excluding ARO & AFUDC
		Amount	Source [1]	Amount	Source [1]		
1	12/1/20##	$	205.46.g	$	205.15,24,34.44.g		$
2	Total						$
		Transmission					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
3	12/1/20##	$	207.58.g	$	207.57.g		$
4	Total						$
		Distribution					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
5	12/1/20##	$	207.75.g	$	207.74.g		$
6	Total						$
		General					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
7	12/1/20##	$	207.99.g	$	207.98.g		$
8	Total						$
		Intangible					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
9	12/1/20##	$	205.5.g	$	CBR		$
10	Total						$
11	December 31, ______ Plant In Service (excluding ARO)						$

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6b - Accumulated Depreciation
Balance as of December 31, _ _ _ _

LINE	RESERVE ACCT (CBR)[1]	RESERVE AMOUNT	PRODUCTION	TRANSMISSION	DISTRIBUTION	GENERAL
1	1080005	$	$	$	$	$
2	1080001 ARO	$	$	$	$	$
3	1080001/1080011	$	$	$	$	$
4	1110001	$	$	$	$	$
5	10800013	$	$	$	$	$
6	TOTAL RESERVE (FF1 200.22.(b)[3].	$	$	$	$	$
7	(Ln 6 – Ln 2) APCo Exc. ARO [1,2]	$	$	$	$	$
8	(Ln 6 – Ln 7) FF1 pg. 219.29.(b)[3]	$	$	$	$	$
9	(Ln 4) FF1 pg. 200.18.(b)[3]	$				
10	(Ln 8 + Ln 9) Total Check FF1 pg. 200.(b).	$				

Notes:
[1] CBR indicates that data comparable to that reported in the FERC From 1 is from the Company's Books and Records.

[2] Note: Excludes reserve on Asset Retirement Obligations, to reflect their removal from gross plant.

[3] References to data from FERC Form 1 are indicated as page#, line#, col.# for the total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6c - General Plant and Intangible Plant
Balances as of December 31, _ _ _ _

Description	Account	12/31/20##
INTANGIBLE PLANT (FF1 205.2-5.g)		
Organization	301	$
Franchises and Consents	302	$
Miscellaneous Intangible Plant	303	$
TOTAL INTANGIBLE PLANT		$
GENERAL PLANT (FF1 207.86-97.g)		
Land	389	$
Structures	390	$
Office Equipment	391	$
Transportation	392	$
Stores Equipment	393	$
Tools, Shop, Garage, Etc.	394	$
Laboratory Equipment	395	$
Power Operated Equipment	396	$
Communications Equipment	397	$
Miscellaneous Equipment	398	$
Fuel Exploration	399	$
TOTAL GENERAL PLANT		$
General Plant (FF1 207.86-97 g)		
Total General and Intangible Exc. ARO		$
Total General and Intangible	205.5.g, 207.99.g	$

Note: Total includes Intangible Plant.
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6d - Depreciation Expense
For the Year Ending December 31, _ _ _ _

Description	Amount	Source
Steam Production	$	FF1, 336, 2, b & d
Hydraulic Production		
Conventional	$	FF1, 336, 4, b
Pumped Storage	$	FF1, 336, 5, b
Other Production Plant	$	FF1, 336, 6 b
Transmission	$	FF1, 336, 7, b
Distribution	$	FF1, 336, 8, b
General	$	FF1, 336, 10, b & d
Intangible Plant	$	FF1, 336, 1,d
Sub-Total	$	
ARO Dep Exp	$	FF1, 336, 12, c
Total Depr Expense	$	FF1, 336, 12, f

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 7

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 281: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 281	$	$	$		
	FF1, pg.273, Ln.8					
2	ACCOUNT 282:					
3	*Listing of Individual Tax Differences*					
4	**TOTAL ACOUNT 282**	$	$	$	$	$
5	***FF1, pg. 275, Ln. 5***					
6	**Labor Related**			$	$	$
7	**Energy Related**			$	$	$
8	**ARO**			$	$	$
9	**Demand Related**			$	$	$
10	**Excluded**			$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
		BALANCE AS	BALANCE AS			
	ACCUMULATED DEFERRED FIT ITEMS	OF 12-31-##	OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
11	ACCOUNT 283:					
12	Listing of Individual Tax Differences					
13	TOTAL ACCOUNT 283	$	$	$	$	$
14						
15	FF1, pg. 277, Ln. 9					
16	Labor Related			$	$	$
17	Energy Related			$	$	$
18	ARO			$	$	$
19	Demand Related			$	$	$
20	Excluded			$		
21	JURISDICTIONAL AMOUNTS FUNCTIONALIZED					

22	TOTAL COMPANY AMOUNTS FUNCTIONALIZED				
23	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT				
24	NOTE: POST 1970 ACCUMULATED DEFERRED				
25	INV TAX CRED. (JDITC) IN A/C 255				
26	SEC ALLOC - ITC - 46F1 - 10%	$	$	$	$
27	HYDRO CREDIT - ITC - 46F1	$	$	$	$
28					
29	TOTAL ACCOUNT 255	$	$	$	$
30	ITC Balance Included in Ratebase	$	$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8ai - ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN O
			NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	PER BOOKS BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 190: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 190 FF 1, p. 234, L. 8 Col. (c)	$	$	$	$	$
Energy Related				$	$	$
ARO				$	$	$
Labor Related				$	$	$
Demand Related				$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8b - Effective Income Tax Rate
For the Year Ending December 31, _ _ _ _'

Effective Income Tax Rate

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * P)} =	%	
EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =	%	
where WCLTD and WACC from Appendix 2 p. 11, Col (4).		
and FIT, SIT & P are as shown below.		
GRCF=1 / (1 - T)		#
Amortized Investment Tax Credit (enter negative)	FF1 P.114, Ln.19, Col.c	$
Federal Income Tax Rate	FIT	%
State Income Tax Rate (Composite).	SIT	%
Percent of FIT deductible for state purposes	P (Note 3)	%
Weighted Cost of Long Term Debt	WCLTD	%
Weighted Average Cost of Capital	WACC	%

Development of Composite State Income Tax Rates for 2011 (Note 1)

Tennessee Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Michigan Business Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Virginia Net Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
West Virginia Net Income	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Illinois Corporation Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Total Effective State Income Tax Rate	%	

Note 1: Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction
.
Note 2: From Company Books and Records.
Note 3: Percent deductible for state purposes provided from Company’s books and records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _ 1/

Payroll Related Other Taxes	$	Payroll
Property Related Other Taxes	$	Property
Direct Production Related	$	Production
Direct Distribution Related	$	Distribution
Other (Misc Taxes Allocated on Gross Plant)	$	Other
Not Allocated ((Gross Receipts, Commission Assessments)	$	NA
	$	

Line No.	(A) Annual Tax Expenses by Type	(B) FERC FORM 1 Tie-Back	(C) FERC FORM 1 Reference	(D) Basis
1	**Revenue Taxes**			
2	Gross Receipts Tax			
		$	P.263.1 ln 7 (i)	N/A
		$	P.263.1 ln 34 (i)	N/A
		$	P.263.1 ln 35 (i)	N/A
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - West Virginia			
		$	P.263 ln 34 (i)	Property
		$	P.263 ln 35 (i)	Property
		$	P.263 ln 37 (i)	Property
		$	P.263 ln 38 (i)	Property
		$	P.263 ln 39 (i)	Property
		$	P.263 ln 40 (i)	Property
		$	P.263.1 ln 2 (i)	Property
		$	P.263.1 ln 3 (i)	Property
5	Real and Personal Property – Virginia			
		$	P.263.2 ln 19 (i)	Property
		$	P.263.2 ln 20 (i)	Property
		$	P.263.2 ln 21 (i)	Property
		$	P.263.2 ln 23 (i)	Property
		$	P.263.2 ln 24 (i)	Property
		$	P.263.2 ln 25 (i)	Property
		$	P.263.2 ln 26 (i)	Property
		$	P.263.2 ln 27 (i)	Property
6	Real and Personal Property – Tennessee			
		$	P.263.3 ln 7 (i)	Property
		$	P.263.3 ln 8 (i)	Property
7	Real and Personal Property - Other Jurisdictions			
		$	P.263.1 ln 37 (i)	Property
		$	P.263.4 ln 5 (i)	Property

1/ This version of Workpaper 8c (“Taxes Other Than Income Taxes”) includes FERC Form 1 line and column references from APCo’s FERC Form 1 for calendar year 2011. These references are illustrative for future years, as Taxes Other Than Income Taxes may be reported on different lines and columns in future APCo FERC Form 1 submissions. In each future FERC Form 1, APCo will report on Page 263 the Taxes Other Than Income Taxes that were paid in the applicable calendar year on a basis similar to the manner in which such Taxes Other Than Income Taxes were reported on APCo’s FERC Form 1 for calendar year 2011.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

Page 2 of 3

Line No.	(A) Annual Tax Expenses by Type	(B) FERC FORM 1 Tie-Back	(C) FERC FORM 1 Reference	(D) Basis
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)	$	P.263 ln 6 (i)	Payroll
10	Federal Unemployment Tax	$	P.263 ln 9 (i)	Payroll
11	State Unemployment Insurance	$	P.263.1 ln 22 (i)	Payroll
		$	P.263.2 ln 34 (i)	Payroll
		$	P.263.3 ln 20 (i)	Payroll
12	**Production Taxes**			
13	State Severance Taxes			
		$		
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax			
		$	P.263 ln 21 (i)	Production
		$	P.263 ln 22 (i)	Production
		$	P.263 ln 23 (i)	Production
16	State Public Service Commission Fees			
		$	P.263 ln 26 (i)	Other
		$	P.263 ln 27 (i)	Other
17	State Franchise Taxes			
		$	P.263.1 ln 25 (i)	Other
		$	P.263.1 ln 28 (i)	Other
		$	P.263.1 ln 29 (i)	Other
		$	P.263.2 ln 8 (i)	Other
		$	P.263.2 ln 9 (i)	Other
		$	P.263.3 ln 4 (i)	Other
		$	P.263.3 ln 33 (i)	Other
18	State Lic/Registration Fee			
		$	P.263.2 ln 11 (i)	Other
		$	P.263.3 ln 12 (i)	Other
		$	P.263.1 ln 13 (i)	Other
19	Misc. State and Local Tax			
		$	P.263.1 ln 11 (i)	Other
		$	P.263.4 ln 23 (i)	Other
		$	P.263.3 ln 24 (i)	Other
20	Sales & Use			
		$	P.263 ln 30 (i)	Other
		$	P.263 ln 31(i)	Other
		$	P.263 ln 32(i)	Other
		$	P.263.2 ln 14 (i)	Other
		$	P.263.2 ln 15 (i)	Other

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

	(A)	(B)	(C)	(D)
Line No.	**Annual Tax Expenses by Type**	**FERC FORM 1 Tie-Back**	**FERC FORM 1 Reference**	Basis
21	Federal Excise Tax			
		$	P.263 ln 14 (i)	Production
22	Michigan Single Business Tax			
		$	P.263.3 ln 12 (i)	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9a - Wages and Salaries
For the Year Ending December 31, _ _ _ _

	APCo [1]	AEPSC [2]	Total
Production:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Transmission:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Distribution:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Customer Accounts	$	$	$
Customer Service and Informational	$	$	$
Sales	$	$	$
Total Wages and Salaries Excluding A & G	$	$	$
Administrative and General			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Total O & M Payroll	$	$	$

[1] APCo Wages and Salaries from FERC Form Pg. 354.
[2] From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9b - Production Payroll Demand/Energy Allocation
For the Year Ended December 31, 20XX

	Account	Demand	Energy	Total	Source CBR[1]
500	Operation Supv & Engineering	$	$		
501	Fuel		$	$	
502	Steam Expenses	$		$	
505	Electric Expenses	$		$	
506	Misc. Steam Power Expense	$		$	
510	Maintenance Supv & Engineering		$	$	
511	Maintenance of Structures	$		$	
512	Maintenance of Boiler Plant		$	$	
513	Maintenance of Electric Plant		$	$	
514	Maintenance of Misc Plant	$		$	
517	Operation Supv & Engineering	$		$	
519	Coolants and Water	$		$	
520	Steam Expenses	$		$	
523	Electric Expenses	$		$	
524	Misc. Nuclear Power Expense	$		$	
528	Maintenance Supv & Engineering		$	$	
529	Maintenance of Structures	$		$	
530	Maintenance of Reactor Plant		$	$	
531	Maintenance of Electric Plant		$	$	
532	Maintenance of Misc. Nuclear Plant		$	$	
535	Operation Supv & Engineering	$		$	
536	Water for Power	$		$	
537	Hydraulic Expenses	$		$	
538	Electric Expenses	$		$	
539	Miscellaneous Hydraulic Power	$		$	
541	Maintenance Supv & Engineering	$		$	
542	Maintenance of Structures	$		$	
543	Maint. of Reservoirs, Dams and Waterways	$		$	
544	Maintenance of Electric Plant		$	$	
545	Maintenance of Misc. Hydraulic Plant	$		$	
546	Operation Supv & Engineering	$		$	
547	Fuel		$	$	
548	Generation Expenses	$		$	
549	Misc. Power Generation Exp	$		$	
553	Maintenance of Generating & Electric Plant	$		$	
554	Maintenance of Misc. Other Power Gen. Plant	$		$	
555	Purchased Power	$	$	$	
556	System Control	$		$	
557	Other Expense	$		$	
	Total Allocated Labor Expense	$	$	$	
		%	%	%	

[1] CBR indicates that data comparable to that reported in the FERC Form 1's from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

Production

	Expense Account		Source
500	Operation Supv & Engineering	$	320.6.(b)
501	Fuel	$	320.7.(b)
502	Steam Expenses	$	320.8.(b)
505	Electric Expenses	$	320.9.(b)
506	Misc. Steam Power Expense	$	320.10.(b)
507	Rents	$	320.11.(b)
509	Allowances	$	320.12.(b)
517	Operation Supv & Engineering	$	320.24.(b)
518	Fuel	$	320.26.(b)
519	Coolants and Water	$	320.27.(b)
520	Steam Expenses	$	320.30.(b)
523	Electric Expenses	$	320.31.(b)
524	Misc. Nuclear Power Expense	$	320.32.(b)
535	Operation Supv & Engineering	$	320.44.(b)
536	Water for Power	$	320.45.(b)
537	Hydraulic Expenses	$	320.46.(b)
538	Electric Expenses	$	320.47.(b)
539	Miscellaneous Hydraulic Power	$	320.48.(b)
540	Rents	$	320.40.(b)
546	Operation Supv & Engineering	$	321.62.(b)
547	Fuel	$	321.63.(b)
548	Generation Expenses	$	321.64.(b)
549	Misc. Power Generation Expense	$	321.65.(b)
	Total Operation	$	320.23.(b)
510	Maintenance Supv & Engineering	$	320.15.(b)
511	Maintenance of Structures	$	320.16.(b)
512	Maintenance of Boiler Plant	$	320.17.(b)
513	Maintenance of Electric Plant	$	320.18.(b)
514	Maintenance of Misc Plant	$	320.19.(b)
528	Maintenance Supv & Engineering	$	320.35.(b)
529	Maintenance of Structures	$	320.36.(b)
530	Maintenance of Reactor Plant	$	320.37.(b)
531	Maintenance of Electric Plant	$	320.38.(b)
532	Maintenance of Misc. Nuclear Plant	$	320.39.(b)
541	Maintenance Supv & Engineering	$	320.53.(b)
542	Maintenance of Structures	$	320.54.(b)
543	Maintenance of Reservoirs, Dams and Waterways	$	320.55.(b)
544	Maintenance of Electric Plant	$	320.56.(b)
545	Maintenance of Miscellaneous Hydraulic Plant	$	320.57.(b)
551	Maintenance Supv & Engineering	$	321.69.(b)
553	Maintenance of Generating & Electric Plant	$	321.71.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

554	Maintenance of Misc. Other Power Gen. Plant	$	321.72.(b)
	Total Maintenance	$	
555	Purchased Power	$	321.76.(b)
556	System Control	$	321.77.(b)
557	Other Expense	$	321.78.(b)
	Total Other	$	
	Total Production	$	
560	Operation Supv & Engineering	$	321.83.(b)
561.1	Load Dispatch-Reliability	$	321.85.(b)
561.2	Load Dispatch-Monitor and Operate	$	321.86.(b)
561.3	Load Dispatch-Transmission Service	$	321.87.(b)
561.4	Scheduling, System Control	$	321.88.(b)
561.5	Reliability, Planning and Standards Dev.	$	321.89.(b)
561.6	Transmission Service Studies	$	321.90.(b)
561.7	Generation Interconnection Studies	$	321.91.(b)
561.8	Reliability, Planning and Standards Dev.	$	321.92.(b)
562	Station Expense	$	321.93.(b)
563	Overhead Line Expense	$	321.94.(b)
564	Underground Line Expense	$	321.95.(b)
565	Trans of Electricity by Others	$	321.96.(b)
566	Misc Transmission Expense	$	321.97.(b)
567	Rents	$	321.98.(b)
	Total Operation	$	
568	Maintenance Supv & Engineering	$	321.101.(b)
569	Maintenance of Structures	$	321.102.(b)
569.1	Maintenance of Computer Hardware	$	321.103.(b)
569.2	Maintenance of Computer Software	$	321.104.(b)
569.3	Maintenance of Communication Equip	$	321.105.(b)
570	Maintenance of Station Equip	$	321.107.(b)
571	Maintenance of OH Lines	$	321.108.(b)
572	Maintenance of UG Lines	$	321.109.(b)
573	Maintenance of Misc Trans	$	321.110.(b)
	Total Maintenance	$	
	Total Transmission	$	
575.7	Market Facilitation, Monitoring and Compliance	$	322.121.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

580	Operation Supv & Engineering	$	322.134.(b)
581	Load Dispatching	$	322.135.(b)
582	Station Expense	$	322.136.(b)
583	Overhead Line Expense	$	322.137.(b)
584	Underground Line Expense	$	322.138.(b)
585	Street Lighting	$	322.139.(b)
586	Meter Expenses	$	322.140.(b)
587	Customer Installations	$	322.141.(b)
588	Misc Distribution Expense	$	322.142.(b)
589	Rents	$	322.143.(b)
	Total Operation	$	322.144.(b)
		$	
590	Maintenance Supv & Engineering	$	322.146.(b)
591	Maintenance of Structures	$	322.147.(b)
592	Maintenance of Station Equip	$	322.148.(b)
593	Maintenance of OH Lines	$	322.149.(b)
594	Maintenance of UG Lines	$	322.150.(b)
595	Maintenance of Line Trsfrs	$	322.151.(b)
596	Maintenance of Street Lights	$	322.152.(b)
597	Maintenance of Meters	$	322.153.(b)
598	Maintenance of Misc Dist Plant	$	322.154.(b)
	Total Maintenance	$	322.155.(b)
	Total Distribution	$	
901	Supervision	$	322.159.(b)
902	Meter Reading Expenses	$	322.160.(b)
903	Customer Records/Collection	$	322.161.(b)
904	Uncollectible Accounts	$	322.162.(b)
905	Misc Customer Accts Exp	$	322.163.(b)
	Total Customer Accounts	$	322.164.(b)
907	Supervision	$	323.167.(b)
908	Customer Assistance	$	322.168.(b)
909	Info & Instructional Adv	$	322.169.(b)
910	Misc Cust Service & Info Expense	$	322.170.(b)
	Total Customer Service	$	
911	Supervision	$	323.174.(b)
912	Selling Expenses	$	323.175.(b)
913	Advertising Expenses	$	323.176.(b)
916	Misc Sales Expense	$	323.177.(b)
	Total Sales Expense	$	

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

920	A & G Salaries	$	323.181.(b)
921	Office Supplies & Exp	$	323.182.(b)
922	Adm Exp Trsfr – Credit	$	323.183.(b)
923	Outside Services	$	323.184.(b)
924	Property Insurance	$	323.185.(b)
925	Injuries and Damages	$	323.186.(b)
926	Employee Benefits	$	323.187.(b)
926a	Less: Actual Employee Benefits (Note A)	$	
926b	Allowed Employee Benefits (Note B)	$6,222,780	
926	Employee Benefits	$	
927	Franchise Requirements	$	323.188(b)
928	Regulatory Commission Exp	$	323.189.(b)
929	Duplicate Charges – Credit	$	323.190.(b)
930.1	General Advertising Expense	$	323.191.(b)
930.2	Misc General Expense	$	323.192.(b)
930.2	Company Dues and Memberships	$	
931	Rents	$	323.193.(b)
	Total Operation	$	323.194.(b)
935	Maintenance of Gen Plant	$	323.196.(b)
	Total Maintenance	$	
	Total Administrative & General	$	323.197.(b)
	Total O & M Expenses	$	323.198.(b)
	Total Elec O & M Exp. - FERC Form1 pg. 323, L. 198(b)	$	
	Difference		

Actual Expense - Removed from Cost of Service		
Note A:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts in Annual Informational Filing	$

Allowable Expense		
Note B:	Acct 926 (0039) PBOP Gross Cost	$ 10,806,289
	Acct 926 (0057) PBOP Medicare Part Subsidy	$(4,583,509)
	PBOP Amounts Recovery Allowance	$6,222,780

Note B: Changing PBOP included in the formula rate will require, as applicable, a FPA Section 205 or Section 206 filing.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 11 – Regulatory Commission Expense
For the Year Ended December 31, 20XX[1/]

Retail		
Misc. Exp.	FF1 pg 351. Ln 34. Col (h).	$
Virginia Base Case	FF1 pg 351. Ln. 35, Col (h).	$
Virginia E&R Filing	FF1 pg 351. Ln. 37, Col (h).	$
Virginia ERAC	FF1 pg 351. Ln. 39, Col (h).	$
Virginia GRAC	FF1 pg 351. Ln. 41, Col (h).	$
Virginia RPS-RAC	FF1 pg 351. Ln. 43, Col (h).	$
West Virginia Base Case	FF1 pg 351. Ln. 45, Col (h).	$
Total Retail		$
Wholesale – FERC[2]		
Smith Mountain	FF1 pg 351. Ln. 3, Col (h).	$
Leesville Hydro Project	FF1 pg 351. Ln. 7, Col (h).	$
Claytor Hydro Project	FF1 pg 351. Ln. 11, Col (h).	$
Byllesby Buck Hydro Project	FF1 pg 351. Ln. 15, Col (h).	$
Marmet and London Hydro Project	FF1 pg 351. Ln. 19, Col (h).	$
Winfield Hydro Project	FF1 pg 351. Ln. 23, Col (h).	$
Ruesens Hydro Project	FF1 pg 351. Ln. 27, Col (h).	$
Niagara Hydro Project	FF1 pg 351. Ln. 31, Col (h).	$
Total Wholesale		$
Total FF1, pg. 351, Ln. 46, Col (h)		$

1) This version of Workpaper 11 (“Regulatory Commission Expense”) includes FERC Form 1 line and column references from APCo’s FERC Form 1 for calendar year 2011. These references are illustrative for future years, as Regulatory Commission Expenses may be reported on different lines and columns in future APCo FERC Form 1 submissions. In each future FERC Form 1, APCo will report on Page 351 the Regulatory Commission Expenses that were incurred in the applicable calendar year on a basis similar to the manner in which such Regulatory Commission Expenses were reported on APCo’s FERC Form 1 for calendar year 2011

2) Assessment for cost of administration of Federal Water Power Act

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, _ _ _ _

Line	Month	Total Capital	Source(s)	Preferred Stock Issued	Premium (Discount)	G(L) on Reacq'd	Source(s)*	Unapprop Sub Earnings	Source	Acc Oth Comp Income	Source	Common Equity Balance
		a		b	C	d		E		f		g=a-b-c-d-e-f
1	12/1/20##	$	112.16.c	$	$	$	112.3.c,6.c., 7.c.	$	112.12. c.	$	112.15. c.	$

NOTE: * Includes preferred portions of capital stock (common and preferred) accounts according to Company Books and Records below.

Line	Account	Description		12/1/20##
2	2010001	Common Stock Issued		$
		Source [1]		*112.2.c*
3	2040002	PS Not Subj to Mandatory Redem		$
		Source [1]		*112.3.c*
4	2070000	Prem on Capital Stk		$
		Source [1]		*112.6.c*
5	2080000	Donations Recvd from Stckhldrs	CBR[2]	$
6	2100000	Gain Rsle/Cancl Req Cap Stock	CBR[2]	$
7	2110000	Miscellaneous Paid-In Capital	CBR[2]	$
8				$
		Source [1]		*112.7.c*
9	2151000	Appropriations of Retained Earnings	CBR[2]	$
10	2160001	Unapprp Retnd Erngs-Unrstrictd	CBR[2]	$
11	4330000	Transferred from Income	CBR[2]	$
12	4370000	Div Decl-PS Not Sub to Man Red	CBR[2]	$
13	4380001	Dividends Declared	CBR[2]	$
14	4390000	Adj to Retained Earnings	CBR[2]	$
		Retained Earnings		$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, _ _ _ _

	Account	Description		12/1/20##
		Source [1]		*112.11.c*
15	2161001	Unap Undist Consol Sub Erng	CBR[2]	$
16	2161002	Unap Undist Nonconsol Sub Erng	CBR[2]	-
17	4181001 & 002	Equity in Earnings	CBR[2]	-
18		Unapprop Sub Earnings	CBR[2]	$
		Source [1]		*112.12.c*
19	2190002	OCI-Min Pen Liab FAS 158-Affil	CBR[2]	$
20	2190004	OCI-Min Pen Liab FAS 158-SERP	CBR[2]	$
21	2190006	OCI-Min Pen Liab FAS 158-Qual	CBR[2]	$
22	2190007	OCI-Min Pen Liab FAS 158-OPEB	CBR[2]	$
23	2190010	OCI-for Commodity Hedges	CBR[2]	$
24	2190015	Accum OCI-Hdg-CF-Int Rate	CBR[2]	$
25	2190016	Accum OCI-Hdg-CF-For Exchg	CBR[2]	-
26		Acc Oth Comp Inc		$
		Source [1]		*112.15.c*
27		Total Capital	CBR[2]	$
28		Common Equity Balance	CBR[2]	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12b - Preferred Stock
For the Year Ending December 31, _ _ _ _

	Preferred Stock		Premium on Preferred						Total Outstanding	Preferred
	A		B						C=A+B	
Month	Acct 204	Source 1	Acct 207	Source 1						Dividends
12/1/20##	$	112.3.c	$	112.6.c					$	$
Total	$		$						$	$

Cost of Preferred Stock = Pfd Dividends/Average Pfd Outstanding Balance = %

NOTES:
(1) All data is from the monthly Balance Sheet of the Company's Books and Records (CBR).
(2) Accounts 207-213 are capital stock accounts containing both common and preferred capital. Preferred portions of these accounts are from the CBR.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13 - Outstanding Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Period	Advances from Associated Co	FF1 Reference	Bonds	FF1 Reference	(Reacquired Bonds)	FF1 Reference	Installment Purchase Contracts	FF1 Reference	Senior Unsecured Notes	FF1 Reference	Debntr Trust Pref Secrty Insts	FF1 Reference	Total Debt Outstanding	Reference
		2230000		2210000		2220001		2240002		2240006		2240046			
		A		b		C		d		e		F		g=a+b+c+d+e+f	
1	12/1/20##	$	112.20.c.	$	112.18.c.	$	112.19.c.	$	257, col. (h)	$	257, col. (h)	$	257, col. (h)	$	FF1, 112,20,c & 112,21,c
2	12/1/20##	$		$		$		$		$		$		$	

Appalachian Power Company
Workpaper 13 Interest & Amortization on Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Description		Acct		Amount
1	Interest	IPC	4270002		$
2	Interest	Unsecured	4270006		$
3	Interest	TPS	4270040		$
4			(FF1, P.117,L.62)		$
5	Amort Debt Disc/ Exp		Acct 428 (FF1, P.117, L.63)		$
6	Amort Loss Reacq		Acct 428.1 (FF1, P.117, L.64)		$
7	Interest*	Assoc LT	4300001 (FF1, P.117, L.67)		$
8	Amort Debt Premium	Amort Gain Reacq	Acct 429 (FF1, P.117, L.65)		$
9			Acct 429.1 (FF1, P.117, L.66)		$
10	Cost of Long Term Debt				$
11	<u>Reconcilation to FF1, 257, 33,</u>				
12	Interest on LT Debt		Line 4		$
13	Interest on Assoc LT Debt		Line 7		$
14	Total (FF1, 257, 33, i)			$	
15	Amortization of Hedge Gain / Loss included in Acct 4270006 (subject to limit on Workpaper 13a)			$	

*Per Company Books and Records Interest associated with LTD.

Reconciliation Account 430

4300001 Interest Expense Long Term Debt	$
4300003 Interest Expense Short Term Debt	$

	FF1, pg. 117, Ln. 67	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13a - Recoverable Hedge Gains/Losses
For the Year Ended December 31, _ _ _ _

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge Gain or Loss for _ _ _ _	Less Excludable Amounts (See NOTE on Line For the Year Ended December 31, _ _ _ _)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
1	Listing of Debt Issues with Hedging	$	$	$	$	11/1/20##	11/1/20##
2		$	$	$	$	12/1/20##	12/1/20##
3		$	$	$	$	11/1/20##	11/1/20##
4		$	$	$	$	12/1/20##	12/1/20##
5		$	$	$	$	11/1/20##	11/1/20##
6		$	$	$	$	12/1/20##	12/1/20##
7		$	$	$	$	11/1/20##	11/1/20##
8		$	$	$	$	12/1/20##	12/1/20##
9		$	$	$	$	11/1/20##	11/1/20##
10		$	$	$	$	12/1/20##	12/1/20##
11	Total Hedge Amortization	$	$	$			

Appalachian Power Company

Capacity Cost of Service Formula Rate

Workpaper 14 - Non-Fuel Power Production O&M Expenses

For the Year Ending December 31, _ _ _ _

Account		December	Less Carbon Capture Expense	Total	Source[1/]
500	Demand	$		$	320.4.(b)
502	Demand	$		$	320.6.(b)
503	Energy	$		$	320.7.(b)
504 - Cr.	Energy	$		$	320.8.(b)
505	Demand	$		$	320.9.(b)
506	Demand	$	$	$	320.10.(b)
507	Demand	$		$	320.11.(b)
509	Energy	$		$	320.12.(b)
510	Energy	$		$	320.15.(b)
511	Demand	$		$	320.16.(b)
512	Energy	$		$	320.17.(b)
513	Energy	$		$	320.18.(b)
514	Demand	$		$	320.19.(b)
517	Demand	$		$	320.24.(b)
519	Demand	$		$	320.26.(b)
520	Demand	$		$	320.27.(b)
521	Demand	$		$	320.28.(b)
522 - Cr.	Demand	$		$	320.29.(b)
523	Demand	$		$	320.30.(b)
524	Demand	$		$	320.31.(b)
525	Demand	$		$	321.32.(b)
528	Energy	$		$	321.35.(b)
529	Demand	$		$	321.36.(b)
530	Energy	$		$	321.37.(b)
531	Energy	$		$	320.38.(b)
532	Energy	$		$	320.39.(b)
535	Demand	$		$	320.44.(b)
536	Demand	$		$	320.45.(b)
537	Demand	$		$	320.46.(b)
538	Demand	$		$	320.47.(b)
539	Demand	$		$	320.48.(b)
540	Demand	$		$	320.50.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 – Non-Fuel Power Production O&M Expense
For Year Ended December 31, 20XX

Account		December	Less Carbon Capture Expense	Total	Source [1/]
541	Demand	$		$	320.53.(b
542	Demand	$		$	320.54.(b
543	Demand	$		$	320.55.(b
544	Energy	$		$	320.56.(b
545	Demand	$		$	320.57.(b
546	Demand	$		$	320.62.(b
548	Demand	$		$	320.64(b
549	Demand	$		$	320.63.(b
550	Demand	$		$	320.64.(b
551	Demand	$		$	320.69.(b
552	Demand	$		$	320.70.(b
553	Demand	$		$	320.71.(b
554	Demand	$		$	320.72.(b
Total		$	$	$	
Demand		$	$	$	
Energy		$	$	$	
Total		$	$	$	
Demand	%			%	
Energy	%			%	
Total	%			%	

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances pages 320-323, ,b.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15a

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15b

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15c - Purchased Power
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Energy ($) [1]	Other Charges [2]	Total Purchased Power Expense
12/1/20##	**$**	**$**	**$**	**$**
Total	**$**	**$**	**$**	**$**
	327, ,,j	327, , k	327,,l	327,,m

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] The deferred portion of APCo's capacity equalization payments related to environmental compliance investments FF 1, pg. 327, column (l)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15d - Off-System Sales
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Other Charges ($) [1]	Energy ($) [1]	Total
12/1/20##	$	$	$	$

Month	($) Margins [2]
12/1/20##	$

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
FF1, 311, h, j, I (Non-RQ)

[2] Margins provided by Accounting (represents 75% of system sales margins)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 16 - GSU Plant and Accumulated Depreciation Balance
For the Year Ending December 31, _______

Company	major_location	asset_location	gl_account	state	utility_account	month	book_cost	allocated_reserve	net_book_value
Listing of Individual GSU Assets							$	$	$
Appalachian Power – Gen Total							$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 17 – Balance of Transmission Investment
Balance as of December _ _ _ _

fr_desc	Fpa	fc_sortid	Description	Beginning_balance	additions	retirements	transfers	Adjustments	ending_balance	start_month	end_month
None	353 - Station Equipment	6	Transmission Plant - Electric	$	$	$	$	$	$	1/1/20##	12/1/20##

<u>Notes:</u>
References to data from FERC Form 1 page(s) 206,207, Ln. 50

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 18 - Fuel Expense
For the Year Ending December 31, _ _ _ _

		Source[1]
Fuel		
Fuel - Account 501	$	320, 5, b
Fuel - Account 518	$	320, 25, b
Fuel - Account 547	$	321, 63, b
Total Fuel	$	
Other		
Fuel Handling	$	CBR[2]
Sale of Fly Ash (Revenue & Expense)	$	CBR[2]

Notes:
1) References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
2) CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 19 - Plant Held for Future Use
For the Year Ending December 31, _ _ _ _

	End of Year		
	Total	Demand [1]	Energy
Production	$	$	$
Transmission	$		
Distribution	$		
General	$		
Total	$	$	$
	FF1, 214, d		

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1
is from the Company's Books and Records.

SCHEDULE 9

PROCEDURES FOR ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of the Interconnection and maintained in the PJM Manuals.

B. The rules and procedures shall recognize the difference in the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow and/or reservoir storage for hydro units, energy storage capability for Energy Storage Resources, energy source variability and intermittency, mechanical limitations, and system operating policies. For this purpose, the basis for determining and demonstrating the capability of a particular generating unit shall be described in RAA, Schedule 9.

C. For Delivery Years through the 2024/2025 Delivery Year

For Unlimited Resources, the capability of the generating unit is based on the level of output that the unit can provide under the site conditions expected to exist at the time of PJM system peak load where such conditions include, but are not limited to, ambient air temperature, humidity, barometric pressure, intake water temperature, and cooling system performance. Generating units with the ability to operate continuously across all hours of an Operating Day without interruption if needed include, but are not limited to, nuclear and fossil-fired steam units, combined cycle units, combustion turbine units, reciprocating engine units, and fuel cell units.

For ELCC Resources, the Office of the Interconnection shall determine the capability of the resource to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.1, with additional implementation details provided in the PJM Manuals.

D. For the 2025/2026 Delivery Year and Subsequent Delivery Years

The Office of the Interconnection shall determine the capability of Generation Capacity Resources to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.2, with additional implementation details provided in the PJM Manuals.

SCHEDULE 9.1:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR DELIVERY YEARS THROUGH THE 2024/2025 DELIVERY YEAR

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources and Combination Resources.

The outputs of the effective load carrying capability analysis include:

-The ELCC Portfolio UCAP, in MW;
-ELCC Class UCAP values, in MW; and
-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)
- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)

- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified below

(2) PJM shall establish Hybrid Resource Classes for all “open-loop” combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all “closed-loop” combinations of each Capacity Storage Resource class and each Variable Resource class. An “open-loop” resource is physically and contractually capable of charging from the grid, while a “closed-loop” resource is not.

(3) PJM shall establish “Other Limited Duration Combination Classes” for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Portfolio UCAP

The effective load carrying capability analysis shall identify a scenario in which the aggregate installed capacity “Y” of a group of Unlimited Resources with no outages yields the same annual loss of load expectation as the one produced by the scenario with all ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed. The ELCC Portfolio UCAP shall be the value “Y”.

D. Allocation from ELCC Portfolio UCAP to ELCC Class UCAP

The ELCC Portfolio UCAP shall be allocated, as specified in the PJM Manuals, to each ELCC Class UCAP according to:

(1) The reliability value of the subject ELCC Class evaluated in the absence of other ELCC Classes, minus

(2) a quantity that is proportional to the product of:

(a) the difference between the reliability value of the subject ELCC Class when evaluated in the presence of the entire portfolio of ELCC Classes and the reliability value of the subject ELCC Class when evaluated in the absence of the other ELCC Classes, and

(b) the difference between the total reliability value of all the ELCC Classes in the model when evaluated jointly and the sum of the reliability values determined individually for each ELCC Class by evaluating the subject ELCC Class in the absence of other ELCC Classes.

E. Calculation of ELCC Class Rating

(1) The ELCC Class Rating of Variable Resources and Limited Duration Resources shall be the ratio of the applicable ELCC Class UCAP to the aggregate Effective Nameplate Capacity of the modeled ELCC Resources of that ELCC Class that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed.

(2) For Combination Resources, there shall be an ELCC Class Rating for each component.

(i) For a Combination Resource with a Limited Duration Resource component and a Variable Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the quotient of (1) the Combination Resource ELCC Class UCAP minus the [product of the Variable Resource ELCC Class Rating and the aggregate Effective Nameplate Capacity of all the Variable Resource components within the subject Combination Resource class] divided by (2) the aggregate equivalent Effective Nameplate Capacity of all the Limited Duration Resource components within the subject Combination Resource class, and the Variable Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Variable Resource component would belong if it were not a component of the Combination Resource.

(ii) For a Combination Resource with a Limited Duration Resource component and an Unlimited Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Limited Duration Resource component would belong if it were not a component of the Combination Resource, and the Unlimited Resource component would not have an ELCC Class Rating.

(3) For ELCC Resources in the Hydropower with Non-Pumped Storage Class and in the Complex Hybrid Class, no ELCC Class Rating is determined. A resource-specific ELCC rating is determined for each such resource.

F. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For Combination Resources, Accredited UCAP values shall be equal to the sum of the Accredited UCAP of each component, but not to exceed the Maximum Facility Output of the resource, where:

(i) The value for a Variable Resource component shall be determined in accordance with subsection (a) above.

(ii) The value for a Limited Duration Resource component shall be equal to the product of:

(A) the Effective Nameplate Capacity determined for the Limited Duration Resource component;

(B) [one minus the EFORd for the Limited Duration Resource component]; and

(C) the applicable Limited Duration Resource component ELCC Class Rating as determined in Section E(2)(i).

(iii) The value for an Unlimited Resource component shall be equal to the product of the installed capacity of the Unlimited Resource component and [one minus the EFORd for the Unlimited Resource component].

(iv) The Accredited UCAP for Hydropower With Non-Pumped Storage, and for each member of an ELCC Class whose members are so distinct from one another that a single ELCC Class Rating fails to capture their physical characteristics, shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource: based on a metric consisting of the average of (1) actual output during the 200 highest coincident peak load hours over the preceding ten years, regardless of the years in which they occur, and (2) actual output during the 200 highest coincident peak putative net load hours over the preceding ten years, regardless of the years in which they occur, where putative net load is actual load minus the putative hourly output of Variable Resources based on the resource mix of the target year. For Planned Resources or resources less than 10 years old, estimated hypothetical historical output will be used to develop this metric. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class.

(b) For Limited Duration Resources: based on EFORd.

(c) For Combination Resources with only an Unlimited Resource component and a Limited Duration Resource component: based on EFORd.

(d) For Combination Resources with a Variable Resource component (except for Hydropower With Non-Pumped Storage): (1) based on the direct metered or estimated output of the Variable Resource component, which is then assessed according to the methodology described in subsection (a) above for Variable Resources and in accordance with the PJM Manuals; and (2) based on the EFORd that is applicable to the Limited Duration Resource component.

(e) For Hydropower With Non-Pumped Storage and other Combination Resources that do not fall into the above categories: based on EFORd.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource’s constituent components considered on a stand-alone basis.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative resource adequacy value of the portfolio of all ELCC Classes, as well of each individual ELCC Class, compared to a group of Unlimited Resources with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual loss of load expectation of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; and (iii) expected output of Limited Duration Resources and of Combination Resources as described below. These expected quantities are based on actual values for load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. This putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals.

The effective load carrying capability analysis shall simulate forced outages of Unlimited Resources based on actual historical data, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above. Forced outages of Limited Duration Resources and Combination Resources shall not be simulated in the effective load carrying capability analysis.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year.

The ELCC Class UCAP and other results of the effective load carrying capability analysis shall be based on the total Effective UCAP of the ELCC Class as a whole.

The ELCC Class UCAP and corresponding ELCC Class Rating values may increase or decrease from year to year as the expected resource mix and load shape change.

Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources and Combination Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis in proportion to their Effective Nameplate Capacity without foresight to future hours. The simulated deployment of Demand Resources shall be such that there is adequate Primary Reserves provided by economic resources, if sufficient simulated Demand Resources are available. Primary Reserves shall be assigned to generation resources in order to maximize simulated reliability, provided that assignments to Limited Duration Resources and Combination Resources shall be pro rata according to their Effective Nameplate Capacity. Primary Reserves shall be exhausted prior to identifying a loss of load event in the analysis. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Starting with the 2023/2024 Delivery Year, Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2026/2027 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection's determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 9.2:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR THE 2025/2026 DELIVERY YEAR AND SUBSEQUENT DELIVERY YEARS

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis shall consider similar data and forecasts as that used in development of the FPR, as described in Schedule 4.C, and will include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources, including consideration of correlated outage risks;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources, Combination Resources, and Demand Resources.

The outputs of the effective load carrying capability analysis include:

-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Intermittent Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)

- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)
- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified in subpart (2) below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified in subpart (3).

(d) The following are the ELCC Classes for Unlimited Resources

- Nuclear Class
- Coal Class
- Gas Combined Cycle Class
- Gas Combustion Turbine Class
- Gas Combined Cycle Dual Fuel Class
- Gas Combustion Turbine Dual Fuel Class
- Diesel Utility Class
- Steam Class
- Other Unlimited Resource Class

(e) The following are the ELCC Classes for Demand Resources

- Demand Resource Class

(2) PJM shall establish Hybrid Resource Classes for all “open-loop” combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all “closed-loop” combinations of each Capacity Storage Resource class and each Variable Resource class. An “open-loop” resource is physically and contractually capable of charging from the grid, while a “closed-loop” resource is not.

(3) PJM shall establish “Other Limited Duration Combination Classes” for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Class Rating

ELCC Class Ratings for a Delivery Year are calculated by adding to the forecasted resource portfolio incremental quantities of resources belonging to the subject ELCC Class, depending on the resource type:

(1) The ELCC Class Rating of Variable Resources, Limited Duration Resources, Unlimited Resources (except Other Unlimited Resources), and Demand Resources shall be the ratio of the expected unserved energy improvement resulting from adding an incremental quantity of the subject ELCC Class to the expected unserved energy improvement resulting from adding an incremental quantity of an Unlimited Resource with no outages, where expected unserved energy improvement is calculated relative to the Portfolio EUE for the Delivery Year.

(2) No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

D. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the lesser of the resource's Capacity Interconnection Right or the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For any resource in an ELCC Class for which no Class Rating has been calculated pursuant to C(2), the Accredited UCAP shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(c) For Unlimited Resources that have an ELCC Class Rating determined pursuant to C(1), Accredited UCAP values shall be equal to the product of:

(i) the installed capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(d) For Demand Resources, Accredited UCAP values shall be equal to the product of:

(i) the Nominated Value of the Demand Resource; and
(ii) the applicable ELCC Class Rating.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource, a Limited Duration Resource, and an Unlimited Resource: based on a metric consisting of the weighted average expected hourly output of the resource in the ELCC model during hours of loss of load risk where: (i) the weights correspond to the modeled probability of losing load in such hour and (ii) the expected hourly output is based on the resource's modeled output during the same hour on days since June 1st, 2012 identified as having similar weather from an RTO-perspective. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class or applicable Unlimited Resource ELCC Class.

In determining the ELCC Resource Performance Adjustment, the actual output of a Variable Resource shall be adjusted to reflect historical curtailments, and output in any hour shall be capped at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, for hours in the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, for hours in the months of November through April of the Delivery Year. The output of an Unlimited Resource in any hour shall be capped at the greater of the resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year..

E. Calculation of Accredited UCAP Factor

For Generation Capacity Resources, PJM shall determine an Accredited UCAP Factor, which is the ratio of the resource's Accredited UCAP to the resource's installed capacity.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis. The installed capacity of an Unlimited Resource and Variable Resource shall be determined in accordance with the PJM Manuals. The installed capacity of Demand Resources, for purposes of the ELCC analysis, is based on the forecasted deployment level in the PJM Load Forecast.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative marginal resource adequacy value of each individual ELCC Class compared to an Unlimited Resource with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; (iii) expected output of Limited Duration Resources and of Combination Resources as described below; (iv) expected Unlimited Resource output; and (v) expected Demand Resource output. These expected quantities are based on forecasted load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) and Unlimited Resource output after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. For Variable Resources, this putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals; for Unlimited Resources, the putative output is developed based on actual performance of similar units in accordance with the PJM Manuals.

Variable Resource actual output shall be adjusted in the ELCC analysis to reflect historical curtailments, and output shall be capped in any hour at: (i) the greater of the Variable Resource’s Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource’s assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. The output of Unlimited Resources shall not exceed the greater of the Unlimited Resource’s Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

The effective load carrying capability analysis shall simulate performance of Demand Resources, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year, and, where applicable, information provided to the Office of the Interconnection regarding intent to offer in an RPM Auction, pursuant to the requirements in the Tariff, Attachment DD, section 5.5.

The model inputs, specifically the load scenarios, shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The resulting expected unserved energy constitutes the Portfolio EUE for the Delivery Year. Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources, Combination Resources, and Demand Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The analysis shall first simulate the output of Demand Resources. If the simulated output of Demand Resources is insufficient to meet load, then the output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis based on their relative duration, starting from longer duration resources to shorter duration resources. The output of Combination Resources shall be capped in any hour at: (i) the greater of the Combination Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Combination Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Years such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection’s determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant’s physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 10

PROCEDURES FOR ESTABLISHING DELIVERABILITY OF GENERATION CAPACITY RESOURCES

Generation Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by obtaining or providing for Network Transmission Service within the PJM Region such that each Generation Capacity Resource is a Network Resource. In addition, for Generation Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Unforced Capacity Obligation, the capacity and energy of such Generation Capacity Resources must comply with the deliverability requirements of PJM Tariff, Attachment DD, section 5.5A, and the receipt of such capacity and energy at the PJM Region interface for delivery to loads in the PJM Region shall be subject to all applicable Capacity Import Limits.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Generation Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in RAA, Schedule 15), combinations of such Zones, and portions of such Zones:

- EKPC
- Cleveland
- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Region (MAR) (consisting of all the zones listed below for Eastern MAR (EMAR), Western MAR (WMAR), and Southwestern MAR (SWMAR))
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, DEOK, EKPC, and OVEC
- EMAR (PSE&G, JCP&L, PECO, AE, DPL & RE)
- SWMAR (PEPCO & BG&E)
- WMAR (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into

PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a CETL less than 1.15 times the CETO of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

SCHEDULE 12

DATA SUBMISSION CHARGES

A. Data Submission Charge

For each working day of delay in the submittal of information required to be submitted under this Agreement, a data submission charge of $500 shall be imposed.

B. Distribution Of Data Submission Charge Receipts

1. Each Party that has satisfied its obligations for data submittals pursuant to RAA, Schedule 11 during a Delivery Year, without incurring a data submission charge related to that obligation, shall share in any data submission charges paid by any other Party that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the sum of the Unforced Capacity Obligations of each such Party entitled to share in the data submission charges for the most recent month.

2. In the event all of the Parties have incurred a data submission charge during a Delivery Year, those data submission charges shall be distributed as approved by the PJM Board.

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

(b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

(c) Monitor the compliance of each Party with its obligations under the Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

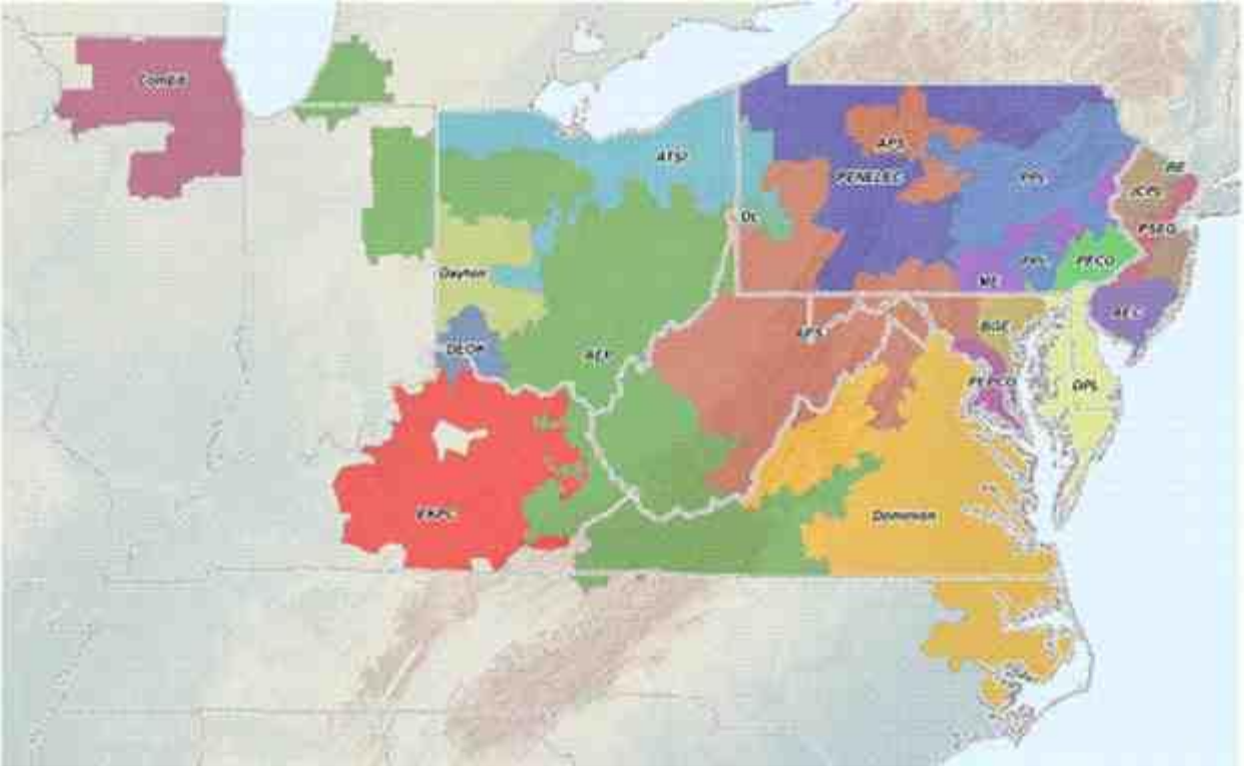
(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Entity principles, guidelines, standards, requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 15
ZONES WITHIN THE PJM REGION



FULL NAME **SHORT NAME**

Pennsylvania Electric Company* .... Penelec
Allegheny Power .... APS
PPL Group ....PPL
Metropolitan Edison Company** ....MetEd
Jersey Central Power and Light Company ....JCPL
Public Service Electric and Gas Company ....PSEG
Atlantic City Electric Company ....AEC
PECO Energy Company .... PECO
Baltimore Gas and Electric Company ....BGE
Delmarva Power and Light Company .... DPL
Potomac Electric Power Company .... PEPCO
Rockland Electric Company .... RE
Commonwealth Edison Company .... ComEd
AEP East Zone .... AEP
The Dayton Power and Light Company ....Dayton
Virginia Electric and Power Company .... Dominion
Duquesne Light Company ……………………………………………. .... DL
American Transmission Systems, Incorporated ………………………ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.……………DEOK
East Kentucky Power Cooperative, Inc. ………………………………EKPC
Ohio Valley Electric Corporation ……………………………………..OVEC

* FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or Penelec Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company or MetEd Zone remain unchanged.

SCHEDULE 16

Non-Retail Behind the Meter Generation
Maximum Generation Emergency Obligations

1. A Non-Retail Behind The Meter Generation resource that has output that is netted from the Daily Unforced Capacity Obligation of a Party pursuant to RAA, Schedule 7 shall be required to operate at its full output during the first ten times between November 1 and October 31 that Maximum Generation Emergency conditions occur in the zone in which the Non-Retail Behind The Meter Generation resource is located.

2. The Party for which Non-Retail Behind The Meter Generation output is netted from its Daily Unforced Capacity Obligation shall be required to report to PJM scheduled outages of the resource prior to the occurrence of such outage in accordance with the time requirements and procedures set forth in the PJM Manuals. Such Party also shall report to PJM the output of the Non-Retail Behind The Meter Generation resource during each Maximum Generation Emergency condition in which the resource is required to operate in accordance with the procedures set forth in PJM Manuals.

3. Except for failures to operate due to scheduled outages during the months of October through May, for each instance a Non-Retail Behind The Meter Generation resource fails to operate, in whole or in part, as required in paragraph 1 above, the amount of operating Non-Retail Behind The Meter Generation from such resource that is eligible for netting will be reduced pursuant to the following formula:

Adjusted ENRBTMG = ENRBTMG – ∑ (10% of the Not Run NRBTMG)

Where:

ENRBTMG equals the operating Non-Retail Behind The Meter Generation eligible for netting as determined pursuant to RAA, Schedule 7.

Not Run NRBTMG is the amount in megawatts that the Non-Retail Behind The Meter Generation resource failed to produce during an occurrence of Maximum Generation Emergency conditions in which the resource was required to operate.

∑ (10% of the Not Run NRBTMG) is the summation of 10% megawatt reductions associated with the events of non-performance.

The Adjusted ENRBTMG shall not be less than zero and shall be applicable for the succeeding Planning Period.

4. If a Non-Retail Behind The Meter Generation resource that is required to operate during a Maximum Generation Emergency condition is an Energy Resource and injects energy into the Transmission System during the Maximum Generation Emergency condition, the Network

Customer that owns the resource shall be compensated for such injected energy in accordance with the PJM market rules.

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
Aggressive Energy LLC
Agway Energy Services, LLC
Algonquin Energy Services Inc.
All American Power and Gas, LLC
All Choice Mid America LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpaca Energy LLC
Alpha Gas and Electric LLC
Ambit Northeast, LLC
American Electric Power Service Corporation on behalf of its affiliates:
    Appalachian Power Company
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Approved Energy II LLC
Archer Energy, LLC
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC

Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
Boston Energy Trading and Marketing LLC
BP Energy Company
BP Energy Retail Company LLC
Brookfield Renewable Energy Marketing US LLC
BTG Pactual Commodities (US) LLC
Buckeye Power, Inc.
Calpine Energy Service, L.P.
Calpine Energy Solutions, LLC
Catalyst Power
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Citigroup Energy Inc.
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of New Martinsville - WV
City of Rochelle
CleanChoice Energy, Inc.
Clearview Electric, Inc.
Cleveland Electric Illuminating Company
Click Energy, LLC
CMS Resource Management Company
Collegiate Clean Energy, LLC
Commonwealth Edison Company
ConocoPhillips Company
Constellation Energy Generation, LLC
Constellation NewEnergy, Inc.

Convanta Energy Marketing LLC
CPV Retail Energy LP
Current Energy and Renewables Inc.
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Diamond Energy East, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
DPL Energy Resources, Inc.
DTE Atlantic, LLC
DTE Energy Trading, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Duquesne Light Energy, LLC
DXT Commodities North America Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
EcoPlus Power, LLC
EDF Trading North America, LLC
Eligio Energy, LLC
Enel Trading North America, LLC
Energetix, Inc.
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Services Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Engie Energy Marketing NA, Inc.
EnPowered USA Inc.
Evergreen Gas & Electric, LLC
Everyday Energy, LLC
FirstEnergy Pennsylvania Electric Company

First Point Power, LLC
Freepoint Energy Solutions LLC
Front Royal (Town of)
Galt Power Inc.
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
Great American Gas & Electric, LLC
Great American Power, LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Grid Power Direct, LLC
Hagerstown Light Department
Harborside Energy, LLC
Harrison REA, Inc. - Clarksburg, WV
Hartee Parnters, LP
Holcim (US) Inc.
Hoosier Energy REC, Inc.
Horizon Power and Light LLC
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
Illinois Power Marketing Company
Inspire Energy Holdings, LLC
Interstate Gas Supply, LLC
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
J. Aron & Company LLC
Jersey Central Power & Light Company
Josco Energy USA, LLC
Just Energy Limited
Just Energy Solutions Inc.
Kentucky Municipal Energy Agency
Kiwi Energy NY LLC
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Land O'Lakes, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
MeadWestvaco Corporation
Median Energy Corp.

Median Energy PA LLC
Mega Energy Holdings, LLC
Mercuria Energy America, Inc.
Messer Energy Services, Inc.
MeterGenius Inc.
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Morgan Stanley Capital Group, Inc.
Morgan Stanley Services Group Inc.
MP2 Energy NE, LLC dba Shell Energy Solutions
MPower NJ LLC
National Gas & Electric, LLC
NextEra Energy Marketing, LLC
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeastern REMC
Northern States Power Company
Northern Virginia Electric Cooperative – NOVEC
NRG Power Marketing, L.L.C.
nTherm, LLC
Octopus Energy LLC
Ohio Edison Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Park Power LLC
Pay Less Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Grain Processing LLC
PEPCO Energy Services, Inc.
Pinnacle Power LLC
Plymouth Rock Energy, LLC
Polaris Power Services LLC
Potomac Electric Power Company
Power UP Energy, LLC

Powervine Energy, LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
Prairieland Energy, Inc.
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
Public Service Electric and Gas Company
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Realgy, LLC
Red Oak Power, LLC
Renaissance Power & Gas, Inc.
ResCom Energy, LLC
Residents Energy, L.L.C.
Respond Power LLC
Riverside Generating Company, LLC
Rolling Hills Generating, LLC
RPA Energy, Inc.
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
S.J. Energy Partners, Inc.
Santanna Energy Services
Seward Generation, LLC
SFE Energy, Inc.
Shipley Choice LLC
Smartest Energy US LLC
Solios Power Mid-Atlantic Trading LLC
South Bay Energy Corp.
South Jersey Energy Company
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Standard Gas & Electric, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Summer Energy Midwest, LLC
SunSea Energy LLC
Talen Energy Marketing, LLC

Tenaska Power Services Co.
Texas Retail Energy, LLC
Think Energy, LLC
Thurmont Municipal Light Company
Titan Gas and Power
Toledo Edison Company (The)
Tomorrow Energy Corp
Town of Berlin, Maryland
Town of Williamsport
Town Square Energy East, LLC
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trustees of the University of Pennsylvania
Twin Eagle Resource Management, LLC
UGI Energy Services, LLC
UGI Utilities, Inc. - Electric Division
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Viridian Energy Ohio LLC
Vista Energy Marketing, L.P.
Volunteer Energy Services, Inc.
Wabash Valley Power Association, Inc.
Wellsboro Electric Company
WGL Energy Services, Inc.
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
Xoom Energy, LLC
York Generation Company, LLC

PJM Interconnection, L.L.C.
Rate Schedule FERC No. 24

AMENDED AND RESTATED

OPERATING AGREEMENT

OF

PJM INTERCONNECTION, L.L.C.

AMENDED AND RESTATED OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.

This Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of this 2nd day of June, 1997, amends and restates as of the Effective Date the Operating Agreement of PJM Interconnection, L.L.C. filed with the FERC on April 2, 1997, as amended.

WHEREAS, certain of the Members have previously entered into an agreement, originally dated September 26, 1956, as amended and supplemented up to and including December 31, 1996, stating "their respective rights and obligations with respect to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems" (such agreement as amended and supplemented being referred to as the "Original PJM Agreement"), and which coordinated operations and interchange came to be known as the PJM Interconnection; and

WHEREAS, pursuant to a resolution of June 16, 1993, an unincorporated association comprised of the parties to the Original PJM Agreement was formed for the purpose of implementation of the Original PJM Agreement as it then existed and as it subsequently has been amended and supplemented, such association being known as the "PJM Interconnection Association"; and

WHEREAS, because of changes in federal law and policy, the Original PJM Agreement, together with other documents and agreements, was amended, restated and submitted to FERC on December 31, 1996 to restructure fundamental aspects of the operation of the Interconnection; and

WHEREAS, so that the provisions of the Original PJM Agreement could be placed into effect consistent with a February 28, 1997 order of FERC, including those provisions related to the governance of the Interconnection, the parties to the Original PJM Agreement, along with the other interested parties, approved the conversion of the PJM Interconnection Association into the LLC pursuant to the provisions of the Delaware Limited Liability Company Act, as amended (the "Delaware LLC Act"), pursuant to a Certificate of Formation (the "Certificate of Formation") and a Certificate of Conversion (the "Certificate of Conversion"), each filed with the Delaware Secretary of State (the "Recording Office") on March 31, 1997; and

WHEREAS, the Members wish to amend and restate the Operating Agreement of PJM Interconnection, L.L.C. adopted in connection with the formation of the LLC and as in effect immediately prior to the Effective Date in the form set forth below; and

WHEREAS, the Members intend to form an Independent System Operator in accordance with the regulations of the Federal Energy Regulatory Commission; and

WHEREAS, the Members wish to amend and restate the Operating Agreement to provide for expansion of the operations of PJM Interconnection, L.L.C. into additional Control Areas.

Now, therefore, in consideration of the foregoing, and of the covenants and agreements hereinafter set forth, the Members hereby agree as follows:

OPERATING AGREEMENT
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1. DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used in this Agreement shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or RAA if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Sections, Schedules, Exhibits or Appendices are to Sections, Schedules, Exhibits or Appendices of this Agreement. As used in this Agreement:

Definitions A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

"Act" shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

"Active and Significant Business Interest" is a term that shall be used to assess the scope of a Member's PJM membership and shall be based on a Member's activity in the PJM RTO and/or Interchange Energy Markets. A Member's Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member's PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member's public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member's recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates' interests within the PJM footprint.

Affected Member:

"Affected Member" shall mean a Member of PJM which as a result of its participation in PJM's markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

"Associate Member" shall mean an entity that satifies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

"Authorized Commission" shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

"Authorized Person" shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

"Board Member" shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Charge Economic Maximum Megawatts:

“Charge Economic Maximum Megawatts” shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

“Charge Economic Minimum Megawatts” shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource without a storage component, or that is physically or contractually incapable of charging from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Committed Offer:

The "Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

"Compliance Monitoring and Enforcement Program" shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A and the PJM Manuals.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45) Schedule A. The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C, Attachment 3, section 2.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Decrement Bid:

"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

"Default Allocation Assessment" shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Designated Entity:

"Designated Entity" shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge

Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode.

Dispatch Rate:

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

"Dynamic Transfer" shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

"Effective Date" shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

"EIDSN, Inc." shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

"Electric Distributor" shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

"Emergency" shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use Customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

"Finance Committee" shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s)for a generation resource.

Definitions G - H

Generating Market Buyer:

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

Generation Capacity Resource:

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

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases, with right equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generation Resource Maximum Output:

"Generation Resource Maximum Output" shall mean, for Customer Facilities identified in an Interconnection Service Agreement or Wholesale Market Participation Agreement, the Generation Resource Maximum Output for a generating unit shall equal the unit's pro rata share of the Maximum Facility Output, determined by the Economic Maximum values for the available units at the Customer Facility. For generating units not identified in an Interconnection Service Agreement or Wholesale Market Participation Agreement, the Generation Resource Maximum Output shall equal the generating unit's Economic Maximum.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hot Weather Alert:

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

Hybrid Resource:

"Hybrid Resource" shall mean an Energy Resource or a Generation Capacity Resource composed of more than one component behind the same Point of Interconnection operating in the capacity, energy, and/or ancillary services market(s) as a single integrated resource, whereby each component is a separate generation and/or storage technology type. A Hybrid Resource forms all or part of a Mixed Technology Facility.

Definitions I - L

Immediate-need Reliability Project:

"Immediate-need Reliability Project" shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Increment Offer:

"Increment Offer" shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

"Incremental Energy Offer" shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit's incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

"Incremental Multi-Driver Project" shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

"Information Request" shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Integer Relaxation:

"Integer Relaxation" shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Operating Agreement, Schedule 1, section 2.2.

Interface Pricing Point:

"Interface Pricing Point" shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service

Interregional Transmission Project:

"Interregional Transmission Project" shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

"LLC" shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Local Plan:

"Local Plan" shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners' planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

"Locational Marginal Price" or "LMP" shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any *reduction in megawatts due to* Regulation*,* Synchronized Reserve*, or Secondary Reserve* assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

"Long-lead Project" shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

"Market Buyer" shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJMSettlement in Tariff, Attachment Q, and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. "Market Participant," when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale. "Market Participant," when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller:

"Market Seller" shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and/or PJMSettlement in Tariff, Attachment Q, and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

"Members Committee" shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

Multi-Driver Project:

"Multi-Driver Project" shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

"NERC Functional Model" shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

NERC Reliability Standards:

"NERC Reliability Standards" shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure:"NERC Rules of Procedure" shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

"Network Resource" shall have the meaning specified in the PJM Tariff.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Non-Disclosure Agreement:

"Non-Disclosure Agreement" shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

"Nonincumbent Developer" shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions O - P

Offer Data:

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

"On-Site Generators" shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as an Economic Load Response Participant or as a Demand Resource, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-time Information System" or "OASIS" shall mean the electronic communication system and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Open-Loop Hybrid Resource:

"Open-Loop Hybrid Resource" shall mean a Hybrid Resource with a storage component that is physically and contractually capable of charging its storage component from the grid.

Operating Day:

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operating Reserve:

"Operating Reserve" shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operator-initiated Commitment:

"Operator-initiated Commitment" shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

"Original PJM Agreement" shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Dispute Resolution Procedures:

"PJM Dispute Resolution Procedures" shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

"PJM Governing Agreements" shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

"PJM Interchange" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix.

PJM Interchange Export:

"PJM Interchange Export" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Mid-Atlantic Region:

"PJM Mid-Atlantic Region" shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

"PJM Region" shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

"PJMSettlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

"PJM South Region" shall mean the Transmission Facilities of Virginia Electric and Power Company.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," or "PJM Open Access Transmission Tariff" shall mean that certain "PJM Open Access Transmission Tariff", including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM West Region:

"PJM West Region" shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

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

Planning Period Balance:

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point-to-Point Transmission Service:

"Point-to-Point Transmission Service" shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Delivery under Tariff, Part II.

PRD Curve:

"PRD Curve" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

"PRD Provider" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

"PRD Reservation Price" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

"PRD Substation" shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-appendix, section 8.

President:

"President" shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert:

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Prohibited Securities:

"Prohibited Securities" shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the "Electric Power Generation, Transmission, and Distribution" industry group under the North American Industry Classification System ("NAICS") or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJMSettlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

"Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

"Public Policy Objectives" shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

"Public Policy Requirements" shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions Q - R

Ramping Capability:

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Regional Entity:

"Regional Entity" shall mean an organization that NERC has delegated the authority to propose and enforce reliability standards pursuant to the Federal Power Act.

Regional RTEP Project:

"Regional RTEP Project" shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Registered Entity:

"Registered Entity" shall mean the entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the PJM Governing Agreements.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Related Parties:

"Related Parties" shall mean, solely for purposes of the governance provisions of the Operating Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of the Operating Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM 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, and as amended from time to time thereafter.

Reliability Coordinator:

"Reliability Coordinator" shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2(h), and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2, and the parallel provisions of Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Revenue Data for Settlements:

“Revenue Data for Settlements” shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

Definitions S – T

Sector Votes:

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

"Securities" shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e)and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

"Senior Standing Committees" shall mean the Members Committee, and the Markets and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

"Short-term Project" shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units):

Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or a storage component of a Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System:

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

"Tie Line" shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

"Transmission Customer" shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

"Transmission Operator" shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall mean an upgrade to a Transmission Owner's own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Definitions U - Z

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

User Group:

"User Group" shall mean a group formed pursuant to Operating Agreement, section 8.7.

VACAR:

"VACAR" shall mean the group of five companies, consisting of Duke Energy Carolinas, LLC; Duke Energy Progress, Inc.; South Carolina Public Service Authority; South Carolina Electric and Gas Company; and Virginia Electric and Power Company.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Voting Member:

"Voting Member" shall mean (i) a Member as to which no other Member is an Affiliate or Related Party, or (ii) a Member together with any other Members as to which it is an Affiliate or Related Party.

Weighted Interest:

"Weighted Interest" shall be equal to (0.1(1/N) + 0.5(B/C) + 0.2(D/E) + 0.2(F/G)), where:

N = the total number of Members excluding ex officio Members and State Consumer Advocates (which, for purposes of Operating Agreement, section 15.2 shall be calculated as of five o'clock p.m. Eastern Time on the date PJM declares a Member in default)

B = the Member's internal peak demand for the previous calendar year (which, for Load Serving Entities under the Reliability Assurance Agreement, shall be that used to calculate Accounted For Obligation as determined by the Office of the

Interconnection pursuant to RAA, Schedule 7averaged over the previous calendar year)

C = the sum of factor B for all Members

D = the Member's generating capability from Generation Capacity Resources located in the PJM Region as of January 1 of the current calendar year, determined by the Office of the Interconnection pursuant to RAA, Schedule 9

E = the sum of factor D for all Members

F = the sum of the Member's circuit miles of transmission facilities multiplied by the respective operating voltage for facilities 100 kV and above as of January 1 of the current calendar year

G = the sum of factor F for all Members

Zone or Zonal:

"Zone" or "Zonal" shall mean an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

2. FORMATION, NAME; PLACE OF BUSINESS

2.1 Formation of LLC; Certificate of Formation.

The Members of the LLC hereby:

(a) acknowledge the conversion of the PJM Interconnection Association into the LLC, a limited liability company pursuant to the Act, by virtue of the filing of both the Certificate of Formation and the Certificate of Conversion with the Recording Office, effective as of March 31, 1997;

(b) confirm and agree to their status as Members of the LLC;

(c) enter into this Agreement for the purpose of amending and restating the rights, duties, and relationship of the Members; and

(d) agree that if the laws of any jurisdiction in which the LLC transacts business so require, the PJM Board also shall file, with the appropriate office in that jurisdiction, any documents necessary for the LLC to qualify to transact business under such laws; and (ii) agree and obligate themselves to execute, acknowledge, and cause to be filed for record, in the place or places and manner prescribed by law, any amendments to the Certificate of Formation as may be required, either by the Act, by the laws of any jurisdiction in which the LLC transacts business, or by this Agreement, to reflect changes in the information contained therein or otherwise to comply with the requirements of law for the continuation, preservation, and operation of the LLC as a limited liability company under the Act.

2.2 Name of LLC.

The name under which the LLC shall conduct its business is "PJM Interconnection, L.L.C."

2.3 Place of Business.

The location of the principal place of business of the LLC shall be 2750 Monroe Blvd., Audubon, Pennsylvania 19403. The LLC may also have offices at such other places both within and without the State of Delaware as the PJM Board may from time to time determine or the business of the LLC may require.

2.4 Registered Office and Registered Agent.

The street address of the initial registered office of the LLC shall be 1209 Orange Street, Wilmington, Delaware 19801, and the LLC's registered agent at such address shall be The Corporation Trust Company. The registered office and registered agent may be changed by resolution of the PJM Board.

3. PURPOSES AND POWERS OF LLC

3.1 Purposes.

The purposes of the LLC shall be:

(a) to operate in accordance with FERC requirements as an Independent System Operator, comprised of the PJM Board, the Office of the Interconnection, and the Members Committee, with the authorities and responsibilities set forth in this Agreement;

(b) as necessary for the operation of the PJM Region as specified above: (i) to acquire and obtain licenses, permits and approvals, (ii) to own or lease property, equipment and facilities, and (iii) to contract with third parties to obtain goods and services, provided that, the LLC may procure goods and services from a Member only after open and competitive bidding; however, open and compeitive bidding shall not be required to the LLC's procurement of goods and services from any Member which does not meet the definition of Prohibited Securities in this Agreement whether or not such Member issues Securities; and

(c) to engage in any lawful business permitted by the Act or the laws of any jurisdiction in which the LLC may do business and to enter into any lawful transaction and engage in any lawful activities in furtherance of the foregoing purposes and as may be necessary, incidental or convenient to carry out the business of the LLC as contemplated by this Agreement.

3.2 Powers.

The LLC shall have the power to do any and all acts and things necessary, appropriate, advisable, or convenient for the furtherance and accomplishment of the purposes of the LLC, including, without limitation, to engage in any kind of activity and to enter into and perform obligations of any kind necessary to or in connection with, or incidental to, the accomplishment of the purposes of the LLC, so long as said activities and obligations may be lawfully engaged in or performed by a limited liability company under the Act.

3.3 Counterparty.

(a) In accordance with Operating Agreement, section 10.1, the Office of the Interconnection shall implement this Agreement and administer the PJM Tariff. Under the Tariff and this Operating Agreement, the LLC administers the provision of transmission service and associated ancillary services to customers and operates and administers various centralized electric power and energy markets. In obtaining transmission service and in these centralized markets, customers conduct transactions with PJMSettlement as a counterparty. Market participants also may conduct bilateral transactions with other market participants and they may self-supply power and energy to the electric loads they serve. Such bilateral and self-supply arrangements are not transactions with PJMSettlement.

(b) For purposes of contracting with customers and conducting financial settlements regarding the use of the transmission capacity of the Transmission System, the LLC has established PJMSettlement. The LLC also has established PJMSettlement as the entity that is the Counterparty with respect to the agreements and transactions in the centralized markets that the LLC administers under the Tariff and the Operating Agreement (i.e., the agreements and transactions that are not bilateral arrangements between market participants or self-supply). PJMSettlement will serve as the Counterparty to Financial Transmission Rights and Auction Revenue Rights instruments held by a Market Participant. Any subsequent bilateral transfer of these instruments by the Market Participant to another Market Participant shall require the consent of PJMSettlement, but shall not implicate PJMSettlement as a contracting party with respect to such subsequent bilateral transfer.

(c) As specified in Operating Agreement, section 11 and Operating Agreement, Schedule 4, Members agree that PJMSettlement is the Counterparty to certain transactions as specified in this Operating Agreement and the PJM Tariff.

(d) As a party to the Consolidated Transmission Owners Agreement, the LLC has acquired the right to use the transmission capacity of the transmission system that is required to provide service under the PJM Tariff and the authorization to resell transmission service using such capacity on the transmission system. Under the Consolidated Transmission Owners Agreement, the LLC compensates the Transmission Owners for the use of their transmission capacity by distributing certain revenues to the Transmission Owners as set forth in the PJM Tariff and the Consolidated Transmission Owners Agreement. The LLC has assigned its right to use the transmission capacity of the Transmission System to PJMSettlement. Accordingly, PJMSettlement shall compensate the Transmission Owners for the use of the transmission capacity required to provide service under the PJM Tariff and this Agreement.

(e) Unless otherwise expressly stated in the PJM Tariff or this Agreement, PJMSettlement shall be the Counterparty to the customers purchasing Transmission Service and Network Integration Transmission Service, and to the other transactions with customers and other entities under the PJM Tariff and this Agreement.

(f) PJMSettlement shall not be a contracting party to other non-transmission transactions that are (i) bilateral transactions between market participants, or (ii) self-supplied or self-scheduled transactions reported to the LLC.

(g) Notwithstanding the foregoing, PJMSettlement shall not be the Counterparty with respect to agreements and transactions regarding the LLC's administration of Tariff, Part IV and Tariff, Part VI, Tariff, Schedule 1, Tariff, Schedule 9 (excluding Schedule 9-PJMSettlement), Tariff, Schedule 10-NERC, Tariff, Schedule 10-RFC, Tariff, Schedule 14, Tariff, Schedule 16, Tariff, Schedule 16-A, and Tariff, Schedule 17.

(h) Confidentiality. PJMSettlement shall be bound by the same confidentiality requirements as the LLC.

(i) PJMSettlement Costs. All costs of the services provided by PJMSettlement for the benefit of Market Participants and Transmission Customers shall be included in the charges for Administrative Services set forth in Schedule 9-PJMSettlement of the PJM Tariff.

(j) Amendment of Previously Effective Arrangements**.**

(i) Transmission Service Agreements. Transmission Service Agreements in effect at the time this section 3.3 becomes effective shall be deemed to be revised to include PJMSettlement as a Counterparty to the Transmission Service Agreement in the same manner and to the same extent as agreements entered after the effective date of this section 3.3.

(ii) Reliability Pricing Model. PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions that occurred prior to the effective date of this section 3.3 and for which delivery will occur after the effective date of this section 3.3 in the same manner and to the same extent as transactions arising from auctions cleared after the effective date of this section 3.3.

(iii) Auction Revenue Rights and Financial Transmission Rights. PJMSettlement shall be the Counterparty with respect to the rights and obligations arising from Auction Revenue Rights and Financial Transmission Rights acquired in an auction or assigned by PJM prior to the effective date of this section 3.3 to the same extent as with respect to rights and obligations arising from auctions or assignments of Auction Revenue Rights and Financial Transmission Rights after the effective date of this section 3.3.

4. EFFECTIVE DATE AND TERMINATION

4.1 Effective Date and Termination.

(a) The existence of the LLC commenced on March 31, 1997, as provided in the Certificate of Formation and Certificate of Conversion which were filed with the Recording Office on March 31, 1997. This Agreement shall amend and restate the Operating Agreement of PJM Interconnection, LLC as of the Effective Date.

(b) The LLC shall continue in existence until terminated in accordance with the terms of this Agreement. The withdrawal or termination of any Member is subject to the provisions of Operating Agreement, section 18.18.

(c) Any termination of this Agreement or withdrawal of any Member from the Agreement shall be filed with the FERC pursuant to Section 205 of the Federal Power Act and shall become effective only upon the FERC's approval, acceptance without suspension, or, if suspended, the expiration of the suspension period before the FERC has issued an order on the merits of the filing.

4.2 Governing Law.

This Agreement and all questions with respect to the rights and obligations of the Members, the construction, enforcement and interpretation hereof, and the formation, administration and termination of the LLC shall be governed by the provisions of the Act and other applicable laws of the State of Delaware, and the Federal Power Act.

5. WORKING CAPITAL AND CAPITAL CONTRIBUTIONS

5.1 Funding of Working Capital and Capital Contributions.

(a) The Office of the Interconnection shall attempt to obtain financing of up to twenty-five percent (25%) of the approved annual operating budget of the LLC adopted by the PJM Board pursuant to Operating Agreement, section 7.5.2 to meet the working capital needs of the LLC, which shall be limited to such working capital needs that arise from timing in cash flows from interchange accounting, tariff administration and payment of the operating costs of the Office of the Interconnection. Such financing, which shall be non-recourse to the Members of the LLC and which shall be for a stated term without penalty for prepayment, may be obtained by borrowing the amount required at market-based interest rates, negotiated on an arm's length basis, (i) from a Member or Members or (ii) from a commercial lender, supported, if necessary, by credit enhancements provided by a Member or Members; provided, however, no Member shall be obligated to provide such financing or credit enhancements. The LLC shall make such filings and seek such approvals as necessary in order for the principal, interest and fees related to any such borrowing to be repaid through charges under the Tariff as appropriate under Operating Agreement, Schedule 3.

(b) In the event financing of the working capital needs of the Office of the Interconnection is unavailable on commercially reasonable terms, the PJM Board may require the Members to contribute capital in the aggregate up to five million two hundred thousand dollars ($5,200,000) for the working capital needs that could not be financed; provided that in such event each Member's obligation to contribute additional capital shall be in proportion to its Weighted Interest, multiplied by the amount so requested by the PJM Board. Each Member that contributes such capital shall be entitled to earn a return on the contribution to the extent such contribution has not been repaid, which return shall be at a fair market rate as determined by the PJM Board but in no event less than the current interest rate established pursuant to 18 C.F.R. § 35.19a(a)(2)(iii); provided further, that any Member not wanting to contribute the requested capital contribution may withdraw from the LLC upon 90 days written notice as provided in Operating Agreement, section 18.18.2.

(c) Authority to borrow capital for LLC Operations. Nothing in section 5.1(a) and (b) above, shall be construed to restrict the authority of the PJM Board to authorize the LLC to borrow or raise capital in excess of twenty-five percent of the approved annual operating budget of the LLC, for working capital or otherwise, as the PJM Board deems appropriate to fund the operations of the LLC, in accordance with the general powers of the LLC under Operating Agreement, section 3.2 to enter into obligations of any kind to accomplish the purposes of the LLC. Nor shall anything in section 5.1(a) and (b) above, in any way restrict the authority of the PJM Board to authorize the LLC to grant to lenders such security interests or other rights in assets or revenues received under the Tariff with respect to the costs of operating the LLC and the Office of the Interconnection and to take such other actions as it deems necessary and appropriate to obtain such financing in accordance with such general powers of the LLC under Operating Agreement, section 3.2.

5.2 Contributions to Association.

All contributions prior to the Effective Date of the original Operating Agreement of PJM Interconnection, L.L.C. of cash or other assets to the PJM Interconnection Association by persons who are now or in the future may become Members of the LLC shall be deemed contributions by such Members to the LLC.

6. TAX STATUS AND DISTRIBUTIONS

6.1 Tax Status.

The LLC shall make all necessary filings under the applicable Treasury Regulations to have the LLC taxed as a corporation.

6.2 Return of Capital Contributions.

(a) In the event Members are required to contribute capital to the LLC in accordance with Operating Agreement, section 5.1, the LLC shall request the Transmission Owners to recover such working capital through charges under the Tariff as provided in Operating Agreement, Schedule 3. In the event all or a portion of the working capital is recovered pursuant to the Tariff, such amount(s) shall be returned to the Members in accordance with their actual contributions.

(b) Except for return of capital contributions and liquidating distributions as provided in the foregoing section and Operating Agreement, section 6.3, respectively, the LLC does not intend to make any distributions of cash or other assets to its Members.

6.3 Liquidating Distribution.

Upon termination or liquidation of the LLC, the cash or other assets of the LLC shall be distributed as follows:

(a) first, in the event the LLC has any liabilities at the time of its termination or dissolution, the LLC shall liquidate such of its assets as is necessary to satisfy such liabilities;

(b) second, any capital contribution in cash or in kind by any Member of the PJM Interconnection Association prior to the Effective Date shall be distributed by the LLC back to such Member in the form received by the PJM Interconnection Association; and

(c) third, any remaining assets of the LLC shall be distributed to the Members in proportion to their Weighted Interests.

7. PJM BOARD

7.1 Composition.

There shall be an LLC Board of Managers, referred to herein as the "PJM Board," composed of nine voting members, with the President as a non-voting member. The nine voting Board Members shall be elected by the Members Committee. A Nominating Committee, consisting of one representative elected annually from each sector of the Members Committee established under Operating Agreement, section 8.1 and three voting Board Members (provided that one such Board Member shall serve only as a non-voting member of the Nominating Committee), shall retain an independent consultant, which shall be directed to prepare a list of persons qualified and willing to serve on the PJM Board. Not later than 30 days prior to each Annual Meeting of the Members, the Nominating Committee shall distribute to the representatives on the Members Committee one nominee from among the list proposed by the independent consultant for each vacancy or expiring term on the PJM Board, along with information on the background and experience of the nominees appropriate to evaluating their fitness for service on the PJM Board; provided, however, that the Nominating Committee in its discretion may nominate, without retaining an independent consultant, a Board member whose term is expiring and who desires to serve an additional term. Elections for the PJM Board shall be held at each Annual Meeting of the Members, for the purpose of selecting the initial PJM Board in accordance with the provisions of Operating Agreement, section 7.3(a), or selecting a person to fill the seat of a Board Member whose term is expiring. Should the Members Committee fail to elect a full PJM Board from the nominees proposed by the Nominating Committee, then the Nominating Committee shall propose a further nominee from the list prepared by the independent consultant (or a replacement consultant) for each remaining vacancy on the PJM Board for consideration by the Members at the next regular meeting of the Members Committee.

7.2 Qualifications.

A Board Member shall not be, and shall not have been at any time within two years of election to the PJM Board, a director, officer or employee of a Member or of an Affiliate or Related Party of a Member. Except as provided in the LLC's Standards of Conduct filed with the FERC, at any time while serving on the PJM Board, a Board Member shall have no direct business relationship or other affiliation with any Member or its Affiliates or Related Parties. Of the nine Board Members, four shall have expertise and experience in the areas of corporate leadership at the senior management or board of directors level, or in the professional disciplines of finance or accounting, engineering, or utility laws and regulation, one shall have expertise and experience in the operation or concerns of transmission dependent utilities, one shall have expertise and experience in the operation or planning of transmission systems, and one shall have expertise and experience in the area of commercial markets and trading and associated risk management.

7.3 Term of Office.

(a) The persons serving as the Board of Managers of the LLC immediately prior to the Effective Date shall continue in office until the first Annual Meeting of the Members. At the first Annual Meeting of the Members, the then current members of the PJM Board who desire to continue in office shall be elected by the Members to serve until the second Annual Meeting of the Members or until their successors are elected, along with such additional persons as necessary to meet the composition requirements of Operating Agreement, section 7.1 and the qualification requirements of Operating Agreement, section 7.2.

(b) A Board Member shall serve for a term of three years commencing with the Annual Meeting of the Members at which the Board Member was elected; provided, however, that two of the Board Members elected at the first Annual Meeting of the Members following the Effective Date shall be chosen by lot to serve a term of one year, three of such Board Members shall be chosen by lot to serve a term of two years and the final two such Board Members shall serve a term of three years; provided further, however, that the initial term of one of the two Board Members elected to fill one of the two new Board seats added in 2003 shall be chosen by lot to serve a term of four years and the initial term of the other Board Member elected to fill the other new Board seat added in 2003 shall serve a term of five years.

(c) Vacancies on the PJM Board occurring between Annual Meetings of the Members shall be filled by vote of the then remaining Board Members; a Board Member so selected shall serve until the next Annual Meeting at which time a person shall be elected to serve the balance of the term of the vacant Board Seat. Removal of a Board Member shall require the approval of the Members Committee.

7.4 Quorum.

The presence in person or by telephone or other authorized electronic means of a majority of the voting Board Members shall constitute a quorum at all meetings of the PJM Board for the transaction of business except as otherwise provided by statute. If a quorum shall not be present, the Board Members then present shall have the power to adjourn the meeting from time to time, until a quorum shall be present. Provided a quorum is present at a meeting, the PJM Board shall act by majority vote of the Board Members present.

7.5 Operating and Capital Budgets; Sources and Uses of Funds.

7.5.1 Finance Committee.

(a) Not later than December 1 of each year, the entities specified below shall select the members of a Finance Committee. The Finance Committee shall be composed of two representatives elected from each sector of the Members Committee as defined in Operating Agreement, section 8.1, one representative of the Office of the Interconnection selected by the President, and two Board Members selected by the PJM Board. The Office of the Interconnection representative shall be the Chair of the Finance Committee. The Chair of the Finance Committee and the two PJM Board Members on the Finance Committee shall not vote on the recommendations of the Finance Committee to the PJM Board and Members Committee. Each Member Representative of the PJM Finance Committee shall be entitled to vote on final recommendations to the PJM Board and the PJM Members Committee. The Member Representatives shall represent the interests of their respective sectors. In accordance with Operating Agreement, section 7.7 and Operating Agreement, section 11.1, the Members Representatives shall avoid undue influence by any Member or group of Members on the operations of PJM and Member management of the business of PJM.

(b) The purpose of the PJM Finance Committee is to review PJM's consolidated financial statements, budgeted and actual capital costs, operating budgets and expenses, and cost management initiatives and in an advisory capacity to submit to the PJM Board its analysis of and recommendations on PJM's annual budgets and on other matters pertaining to the appropriate level of PJM's rates, proposed major new investments and allocation and disposition of funds consistent with PJM's duties and responsibilities as specified in Operating Agreement, section 7.7. The Finance Committee shall also review and comment upon any additional or amended budgets prepared by the Office of the Interconnection at the request of the PJM Board or the Members Committee. Copies of the Finance Committee's submissions to the PJM Board shall be provided to the Members Committee.

(c) The Office of the Interconnection shall prepare annual operating and capital budgets and multi-year projections of expenses and capital in accordance with processes and procedures established by the PJM Board, and shall timely submit its budgets to the Finance Committee for review. The Office of the Interconnection shall also provide the Finance Committee with such additional financial information regarding other matters pertaining to the appropriate level of PJM's rates, proposed major new investments and allocation and disposition of funds as may be reasonably requested by the Finance Committee to assist it with its review. PJM shall provide complete and transparent financial data and reporting to all Members through the PJM Finance Committee, such data and reporting to include but not necessarily be limited to: unaudited quarterly PJM financial statements; audited annual PJM financial statements; quarterly PJM FERC Form 3-Q; annual PJM FERC Form 1; and PJM budget and forecast data and Results.

7.5.2 Adoption of Budgets.

The PJM Board shall adopt, upon consideration of the advice and recommendations of the Finance Committee, operating and capital budgets for the LLC, and shall distribute to the

Members for their information final annual budgets for the following fiscal year not later than 60 days prior to the beginning of each fiscal year of the LLC.

7.6 By-laws.

To the extent not inconsistent with any provision of this Agreement, the PJM Board shall adopt such by-laws establishing procedures for the implementation of this Agreement as it may deem appropriate, including but not limited to by-laws governing the scheduling, noticing and conduct of meetings of the PJM Board, selection of a Chair and Vice Chair of the PJM Board, action by the PJM Board without a meeting, and the organization and responsibilities of standing and special committees of the PJM Board. Such by-laws shall not modify or be inconsistent with any of the rights or obligations established by this Agreement.

7.7 Duties and Responsibilities of the PJM Board.

In accordance with this Agreement, the PJM Board shall supervise and oversee all matters pertaining to the PJM Region and the LLC, and carry out such other duties as are herein specified, including but not limited to the following duties and responsibilities:

i) As its primary responsibility, ensure that the President, the other officers of the LLC, and Office of the Interconnection perform the duties and responsibilities set forth in this Agreement, including but not limited to those set forth in Operating Agreement, section 9.2, Operating Agreement, section 9.3, Operating section 9.4, and Operating Agreement, section 10.4 in a manner consistent with (A) the safe and reliable operation of the PJM Region, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and (C) the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Region;

ii) Select the Officers of the LLC;

iii) Adopt budgets for the LLC;

iv) Approve The Regional Transmission Expansion Plan in accordance with the provisions of the Regional Transmission Expansion Planning Protocol set forth in Operating Agreement, Schedule 6;

v) On its own initiative or at the request of a User Group as specified herein, submit to the Members Committee such proposed amendments to this Agreement or any Schedule hereto, or a proposed new Schedule, as it may deem appropriate;

vi) Petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings;

vii) Review for consistency with the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region any change to rate design or to non-rate terms and conditions proposed by Transmission Owners for filing under section 205 of the Federal Power Act;

viii) If and to the extent it shall deem appropriate, intervene in any proceeding at FERC initiated by the Members in accordance with Operating Agreement, section 11.5(b), and participate in other state and federal regulatory proceedings relating to the interests of the LLC;

ix) Review, in accordance with Operating Agreement, section 15.1.3, determinations of the Office of the Interconnection with respect to events of default;

x) Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to PJMSettlement and the Office of the Interconnection, including interest thereon, as to which a Member is in default;

xi) Establish reasonable sanctions for failure of a Member to comply with its obligations under this Agreement;

xii) Direct the Office of the Interconnection on behalf of the LLC and PJMSettlement to take appropriate legal or regulatory action against a Member (A) to recover any unpaid amounts due from the Member to the Office of the Interconnection under this Agreement and to make whole any Members subject to an assessment as a result of such unpaid amount, or (B) as may otherwise be necessary to enforce the obligations of this Agreement;

xiii) [Reserved.]

xiv) [Reserved.]

xv) Solicit the views of Members on, and commission from time to time as it shall deem appropriate independent reviews of, (a) the performance of the PJM Interchange Energy Market, (b) compliance by Market Participants with the rules and requirements of the PJM Interchange Energy Market, and (c) the performance of the Office of the Interconnection under performance criteria proposed by the Members Committee and approved by the PJM Board; and

xvi) Terminate a Member as may be appropriate under the terms of this Agreement.

8. MEMBERS COMMITTEE

8.1 Sectors.

8.1.1 Designation.

Voting on the Senior Standing Committees shall be by sectors. The Senior Standing Committee shall be composed of five sectors, one for Generation Owners, one for Other Suppliers, one for Transmission Owners, one for Electric Distributors, and one for End-Use Customers, provided that there are at least five Members in each Sector. Except as specified in Operating Agreement, section 8.1.2, each Voting Member shall have one vote. Each Voting Member shall, within thirty (30) days after the Effective Date or, if later, thirty (30) days after becoming a Member, and thereafter not later than 10 days prior to the Annual Meeting of the Members for each annual period beginning with the Annual Meeting of the Members, submit to the President a sealed notice of the sector in which it is qualified to vote or, if qualified to participate in more than one sector, its rank order preference of the sectors in which it wishes to vote, and shall be assigned to its highest-ranked sector that has the minimum number of Members specified above. If a Member is assigned to a sector other than its highest-ranked sector in accordance with the preceding sentence, its higher sector preference or preferences shall be honored as soon as a higher-ranked sector has five or more Members. A Voting Member may designate as its voting sector any sector for which it or its Affiliate or Related Party Members is qualified. The sector designations of the Voting Members shall be announced by the Office of the Interconnection at the Annual Meeting and shall apply to all Senior Standing Committees.

8.1.2 Related Parties.

The Members in a group of Related Parties shall each be entitled to a vote, provided that all the Members in a group of Related Parties that chooses to exercise such rights shall be assigned to the Electric Distributor sector.

8.1.3 Sector Challenge.

(a) Any Member (“Challenging Member’) may request that PJM review the qualification of another Member (“Challenged Member”) in the Challenging Member’s sector to participate in that sector. Any five Members may request that PJM review the qualification of another Member to participate in the sector in which that Member is presently assigned.

(b) A request pursuant to section 8.1.3(a) above, (“Challenge”) shall be submitted in writing and shall describe the basis for the Challenge, which shall include, but not limited to, the reasons why the Challenged Member may not have any Active and Significant Business Interests in its present sector. Except for new Members, a Challenge must be submitted within 30 days after the Annual Meeting of the Members. For new Members, a Challenge must be submitted within 30 days after the meeting in which they are introduced.

(c) PJM shall review the Challenge and inform the Challenged Member of the Challenge by providing a copy of the Challenge to the Challenged Member as soon as practicable, and in no case later than 10 working days after PJM receives the Challenge.

(d) The Challenged Member shall submit to PJM a list of the sectors in which it is qualified to vote and its rank order preference of those sectors. PJM may also request information from the Challenged Member to assist in determining the Active and Significant Business Interests of Challenged Member. The Challenged Member shall respond to any such request within 60 days from the date of the request, which shall be the date the request was issued by PJM.

(e) Considering the sector definitions and Active and Significant Business Interests, PJM, in its sole discretion, shall determine if the Challenged Member meets the requirements to participate in its present sector. PJM shall make this determination within the later of 30 days after receiving the information provided pursuant to section 8.1.3(d) above, or 10 days after the next scheduled meeting of the Members Committee.

(f) If the Challenged Member does not meet the requirements for its present sector, PJM shall assign the Challenged Member to the next highest preferred sector for which it is qualified in accordance with the rank order preference established by the Challenged Member pursuant to section 8.1.3(d) above.

(g) PJM shall notify the Challenged Member and Challenging Member as soon as practicable after making a determination pursuant to section 8.1.3(e) above, and shall announce the outcome of any such determination at the Members Committee meeting following PJM's decision. PJM shall disclose the identity of the Challenging Party and the Challenged Party when making the announcement.

(h) If a sector is required pursuant to section 8.1.3(e) above, it shall become effective on the date of the Members Committee meeting following PJM's decision.

(i) Until PJM rules on a Challenge, the Challenged Member shall remain in its present sector and shall be permitted to vote in that sector.

8.2 Representatives.

8.2.1 Appointment.

Each Member may appoint one representative to serve on each of the Standing Committees, potentially a different person for each committee, with authority to act for that Member with respect to actions or decisions thereof. Each Member may appoint up to three alternate representatives to each such committee to act for that Member at meetings thereof in the absence of the representative. A Member participating in the PJM Interchange Energy Market through an agent may be represented on the Standing Committee by that agent. A Member shall appoint its representatives and alternates by giving written notice thereof to the Office of the Interconnection. Members that are Affiliates or Related Parties may each appoint a representative and alternate representatives to each of the Standing Committees, but shall vote on Senior Standing Committees as specified in Operating Agreement, section 8.1.

8.2.2 Regulatory Authorities.

FERC and any other federal agency with regulatory authority over a Member and each State electric utility regulatory commission with regulatory jurisdiction within the PJM Region, may nominate one representative to serve as an ex officio non-voting member on each of the Standing Committees.

8.2.3 State Offices of Consumer Advocate.

(a) Each State Consumer Advocate may nominate one representative to serve as an ex officio member on each of the Standing Committees. Upon a written request by a State Consumer Advocate to the Office of the Interconnection, and upon the payment of the fee prescribed by Operating Agreement, Schedule 3, section (b), a State Consumer Advocate may designate a representative to each of the Standing Committees who, subject to subparagraph b, shall be entitled to cast one (1) non-divisible vote in the End-Use Customer Sector in Senior Standing Committees. As an ex officio member, a State Consumer Advocate shall have no liability under this Agreement, other than the annual fee required by Operating Agreement, Schedule 3. The State Consumer Advocates shall not be entitled to indemnification by the other Members under any provisions of this Agreement. Additionally, the State Consumer Advocates shall not be eligible to participate in any markets managed by PJM under the terms contained in this Agreement.

(b) Each State Consumer Advocate shall be entitled to cast only one (1) vote in the Senior Standing Committees per State or the District of Columbia. If more than one representative from a given state has been nominated to be a voting member of the Senior Standing Committees, all State Offices of Consumer Advocate from such state that have nominated representatives to vote at the Senior Standing Committees shall designate to the Office of the Interconnection one (1) representative who shall be entitled to vote on all of their behalf's, prior to being permitted to vote at any meetings of the Senior Standing Committees.

8.2.4 Initial Representatives.

Initial representatives to the Members Committee shall be appointed no later than 30 days after the Effective Date; provided, however, that each representative to the Management Committee under the Operating Agreement of PJM Interconnection, L.L.C. as in effect immediately prior to the Effective Date shall automatically become a representative to the Members Committee on the Effective Date unless replaced as specified in section 8.2.5 below. An entity becoming a Member shall appoint a representative to each Standing Committee no later than 30 days after becoming a Member.

8.2.5 Change of or Substitution for a Representative.

Any Member may change its representative or alternate on the Standing Committees at any time by providing written notice to the Office of the Interconnection identifying its replacement representative or alternate. Any representative to the Standing Committees may, by written notice to the applicable Chair, designate a substitute representative from that Member to act for him or her with respect to any matter specified in such notice.

8.3 Meetings.

8.3.1 Regular and Special Meetings.

The Standing Committees shall hold regular meetings, no less frequently than once each calendar quarter at such time and at such place as shall be fixed by the Chair thereof. The Members Committee may adopt bylaws, including rules of procedure, governing its meetings and activities and the meetings and activities of the other Standing Committees, and other committees, subcommittees, task forces, working groups and other bodies under its auspices. The Members Committee shall hold an Annual Meeting of the Members each calendar year at such time and place as shall be specified by the Chair. At the Annual Meeting of the Members, Board Members as necessary shall be elected. The Standing Committees may hold special meetings for one or more designated purposes within the scope of the authority of the applicable committee when called by the Chair on the Chair's own initiative, or at the request of five or more representatives on the applicable committee. The notice of a regular or special meeting shall be distributed to the representatives as specified in Operating Agreement, section 18.14 not later than seven days prior to the meeting, shall state the time and place of the meeting, and shall include an agenda sufficient to notify the representatives of the substance of matters to be considered at the meeting; provided, however, that meetings may be called on shorter notice at the discretion of the Chair as the Chair shall deem necessary to deal with an emergency or to meet a deadline for action.

8.3.2 Attendance.

Regular and special meetings may be conducted in person or by telephone, or other electronic means as authorized by the Members Committee. The attendance in person or by telephone or other electronic means of a representative or a duly designated substitute shall be required in order to vote.

8.3.3 Quorum.

The attendance as specified in Operating Agreement, section 8.3.2 of a majority of the Voting Members from each of at least three sectors that each have at least five Members shall constitute a quorum at any meeting of the Members Committee; however, a quorum shall only require ten Voting Members from any sector that has more than 20 Voting Members. At the beginning of any meeting of the Members Committee, a determination shall be made if a quorum is present. Once the determination is made that a quorum is present at the beginning of the meeting, a quorum will be deemed to continue during the entire scheduled time of the meeting, as specified in the notice of the meeting that is published and distributed as specified in Operating Agreement, section 8.3.1. Actions taken during this scheduled time will be deemed to have been taken with a quorum present, and quorum calls are not permitted during this scheduled time. Other than actions taken during the scheduled time for meeting of the Members Committee in accordance with this rule, no action may be taken by the Members Committee at a meeting unless a quorum is present. However, if a meeting of the Members Committee extends beyond its scheduled time, any Voting Members then present shall have the right to request a quorum call. The Voting Members then present shall have the power to adjourn the meeting from time to time until a quorum shall be present. At the discretion of the Chair, administrative or reporting items may be accomplished if a quorum is not deemed to be present. A quorum shall not be required to conduct a meeting of any Committee other than the Members Committee; however, the Chair of any committee other than the Members Committee, in his discretion, may declare adjourned any meeting which fewer than ten Members attend.

8.4 Manner of Acting.

(a) The procedures for the conduct of meetings of the Standing Committees may be stated in bylaws adopted by the Members Committee.

(b) In a Senior Standing Committee, each Sector shall be entitled to cast one and zero one-hundredths (1.00) Sector Votes. Each Voting Member shall be entitled to cast one (1) non-divisible vote in its sector. In the case of a Voting Member comprised of Affiliates or Related Parties, any representative, alternate or substitute of any of the Affiliated or Related Parties may cast the vote of the Voting Member. The Sector Vote of each sector shall be split into an affirmative component based on votes for the pending motion, and a negative component based on votes against the pending motion, in direct proportion to the votes cast within the sector for and against the pending motion, rounded to two decimal places.

(c) The sum of affirmative Sector Votes necessary to pass a pending motion in a Senior Standing Committee shall be greater than (but not merely equal to) the product of .667 multiplied by the number of sectors that have at least five Members and that participated in the vote; provided, however, that the sum of the affirmative Sector Votes necessary to pass a motion to elect a Board Member or to elect the Chair or Vice Chair of the Members Committee shall be greater than (but not merely equal to) the product of .5 multiplied by the number of sectors that have at least five Members and that participated in the vote.

(d) Voting Members not in attendance at the meeting as specified in Operating Agreement, section 8.3.2 or abstaining shall not be counted as affirmative or negative votes.

8.5 Chair and Vice Chair of the Members Committee.

8.5.1 Selection and Term.

The representatives or their alternates or substitutes on the Members Committee shall elect from among the representatives a Chair and a Vice Chair. The offices of Chair and Vice Chair shall be held for a term of one year. The terms shall commence at the last regular meeting of the Members Committee each calendar year and end at the last regular meeting of the Members Committee of the following calendar year or until succession to the office occurs as specified herein. Except as specified below, at the last regular meeting of the Members Committee each calendar year, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected. If the office of Chair becomes vacant, or the Chair leaves the employment of the Member for whom the Chair is the representative, or the Chair is no longer the representative of such Member, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee, both such officers to serve until the last regular meeting of the Members Committee of the calendar year following such succession or election to a vacant office. If the office of Vice Chair becomes vacant, or the Vice Chair leaves the employment of the Member for whom the Vice Chair is the representative, or the Vice Chair is no longer the representative of such Member, a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee.

Notwithstanding the foregoing, the Chair and Vice Chair whose terms commenced on May 1, 2003, shall hold their offices until the last regular meeting of the Members Committee in 2004, and there shall not be an election of a new Vice Chair at the last regular meeting of the Members Committee in 2003.

8.5.2 Duties.

The Chair shall call and preside at meetings of the Members Committee, and shall carry out such other responsibilities as the Members Committee shall assign. The Chair shall cause minutes of each meeting of the Members Committee to be taken and maintained, and shall cause notices of meetings of the Members Committee to be distributed. The Vice Chair shall preside at meetings of the Members Committee in the absence of the Chair, and shall otherwise act for the Chair at the Chair's request.

8.6 Senior, Standing, and Other Committees.

The Members Committee shall establish and maintain the Markets and Reliability Committee as a Senior Standing Committee. The Members Committee also shall establish and maintain the Market Implementation Committee, Planning Committee, Operating Committee and Risk Management Committee (all under the Markets and Reliability Committee) as Standing Committees. The Members Committee may establish or dissolve other Standing Committees from time to time. The President shall appoint the Chair and Vice Chair of each Senior Standing Committee and Standing Committee and, after consultation with the Chair of a Standing Committee, the President shall appoint the Chair and Vice Chair of any other committees.

8.6.1 Markets and Reliability Committee.

The Markets and Reliability Committee shall be established by and report to the Members Committee.

The Markets and Reliability Committee shall provide advice and recommendations concerning the reliable and secure operation of the PJM Interchange Energy Market and Ancillary Services markets, mechanisms to provide an efficient marketplace for products needed for resource adequacy and operating security, and otherwise as directed by the Members Committee. The Markets and Reliability Committee also addresses matters related to the reliable and secure operation of the PJM system and planning strategies to assure the continued ability of the Members to operate reliably and economically, consistent with reliability principles and standards.

Voting on the Markets and Reliability Committee shall be by sectors in accordance with Operating Agreement, section 8.1 and Operating Agreement, section 8.4. Neither the Markets and Reliability Committee nor the Members Committee shall have authority to control or direct the actions of the PJM Board or the Office of the Interconnection with regard to the short-term reliability of grid operations within the PJM Region. The responsibilities of the Markets and Reliability Committee shall, more specifically, include, but not be limited to, the following:

(a) The Markets and Reliability Committee shall develop and approve a Markets and Reliability Committee Annual Plan including prioritization of planned activities and initiation of activities supporting the approved plan.

(b) The Markets and Reliability Committee shall provide advice and recommendations concerning issues pertaining to the operation and administration of the PJM markets, including but not limited to amendments to PJM's Operating Agreement, the PJMTariff, or market rules and procedures as necessary or appropriate to foster competition and assure the fair, reliable and efficient operation and administration of the PJM markets, as well as the reliable operation of the grid.

(c) The Markets and Reliability Committee shall provide advice and recommendations as are necessary or appropriate to assure a high level of economy of service in the operation of the PJM Interchange Energy Market and other markets, in accordance with established market operation principles, practices and procedures, recognizing individual participant requirements for services, contractual obligations and other pertinent factors.

(d) The Markets and Reliability Committee shall provide advice and recommendations concerning studies and analyses relating to the overall efficacy of the PJM Interchange Energy Market and in carrying out actions as may be initiated as a result thereof.

(e) The Markets and Reliability Committee shall provide advice and recommendations concerning revisions to the Operating Agreement, the Reliability Assurance Agreement, and the PJM Tariff that pertain to its areas of responsibility.

(f) The Markets and Reliability Committee shall make annual and timely recommendations concerning the generating capacity reserve requirement and related demand-side valuation factors for consideration by the Members Committee, in order to assist the Members Committee in making recommendations to the PJM Board of Managers.

(g) The Markets and Reliability Committee shall provide direction to the Market Implementation Committee, which committee shall report to the Markets and Reliability Committee. The Market Implementation Committee shall provide advice and recommendations to the Markets and Reliability Committee directed to the advancement and promotion of competitive wholesale electricity markets in the PJM Region, and perform such other functions as the Markets and Reliability Committee may direct from time to time.

(h) The Markets and Reliability Committee shall provide direction to the Operating Committee and Planning Committee, which committees shall report to the Markets and Reliability Committee. The Operating Committee shall advise the Markets and Reliability Committee and PJM on matters pertaining to the reliable and secure operation of the PJM Region and the PJM Interchange Energy Market, as appropriate, and other matters as the Markets and Reliability Committee may request. The Planning Committee shall advise the Markets and Reliability Committee and PJM on matters pertaining to system reliability, security, economy of service, and planning strategies and policies and other matters as the Markets and Reliability Committee may request. The Markets and Reliability Committee shall review technical recommendations and changes initiated by the Operating Committee and Planning Committees and provide comments as needed.

(i) The Markets and Reliability Committee shall perform such other functions, directly or through delegation to a Standing Committee, subcommittee, working group or task force reporting to the Markets and Reliability Committee, as the Members Committee may direct.

(j) The Markets and Reliability Committee shall create subcommittees, working groups or task forces when needed to assist in carrying out the duties and responsibilities of the Markets and Reliability Committee.

8.6.2 [Reserved.]

8.6.3 Other Committees and Bodies.

The Standing Committees may form, select the membership, and oversee the activities, of such other committees, subcommittees, task forces, working groups or other bodies as it shall deem appropriate, to provide advice and recommendations to the Standing Committees or Office of the Interconnection. Each such group shall terminate automatically upon completion of its assigned tasks and, if not terminated, shall terminate two years after formation unless reauthorized by the Standing Committee that directed its formation.

8.7 User Groups.

(a) Any five or more Members sharing a common interest may form a User Group, and may invite such other Members to join the User Group as the User Group shall deem appropriate. Notification of the formation of a User Group shall be provided to all Members of the Members Committee.

(b) The Members Committee shall create a User Group composed of representatives of bona fide public interest and environmental organizations that are interested in the activities of the LLC and are willing and able to participate in such a User Group.

(c) Meetings of User Groups shall be open to all Members and the Office of the Interconnection. Notices and agendas of meetings of a User Group shall be provided to all Members that ask to receive them.

(d) Any recommendation or proposal for action adopted by affirmative vote of three-fourths or more of the Members of a User Group shall be submitted to the Chair of the Members Committee. The Chairman shall refer the matter for consideration by the applicable Standing Committee as appropriate for consideration at that Committee's next regular meeting, occurring not earlier than 30 days after the referral, for a recommendation to the Members Committee for consideration at its next regular meeting.

(e) If the Members Committee does not adopt a recommendation or proposal submitted by a User Group, upon vote of nine-tenths or more of the members of the User Group the recommendation or proposal may be submitted to the PJM Board for its consideration in accordance with Operating Agreement, section 7.7(v).

8.8 Powers of the Members Committee.

The Members Committee, acting by adoption of a motion as specified in Operating Agreement, section 8.4, shall have the power to take the actions specified in this Agreement, including:

i) Elect the members of the PJM Board;

ii) In accordance with the provisions of Operating Agreement, section 18.6 , amend any portion of this Agreement, including the Schedules hereto, or create new Schedules, and file any such amendments or new Schedules with FERC or other regulatory body of competent jurisdiction;

iii) Adopt bylaws that are consistent with this Agreement, as amended or restated from time to time;

iv) Terminate this Agreement; and

v) Provide advice and recommendations to the PJM Board and the Office of the Interconnection.

9. OFFICERS

9.1 Election and Term.

The officers of the LLC shall consist of a President, a Secretary and a Treasurer. The PJM Board may elect such other officers as it deems necessary to carry out the business of the LLC. All officers shall be elected by the PJM Board and shall hold office until the next annual meeting of the PJM Board and until their successors are elected. Any number of offices may be held by the same person, except that the offices of the President and Treasurer may not be held by the same person.

9.2 President.

The PJM Board shall appoint a President and Chief Executive Officer of the LLC (the "President"). The President shall direct and supervise the day-to-day operation of the LLC, and shall report to the PJM Board. The President shall be responsible for directing and supervising the Office of the Interconnection in the performance of the duties and responsibilities specified in Operating Agreement, section 10.4. The President shall execute bonds, mortgages and other contracts requiring a seal, under the seal of the LLC, except where required or permitted by law to be otherwise signed and executed and except where the signing and execution thereof shall be expressly delegated by the board to some other officer or agent of the LLC. In the absence of the President or in the event of his or her inability or refusal to act, and if a vice president has been appointed by the PJM Board, the Vice President (or in the event there be more than one Vice President, the Vice Presidents in the order designated by the PJM Board in its Minutes) shall perform the duties of the President, and when so acting, shall have all the powers of and be subject to all the restrictions upon the President. The Vice President shall perform such other duties and have such other powers as the PJM Board may from time to time prescribe.

9.3 Secretary.

The Secretary shall attend all meetings of the PJM Board and record all the proceedings of the meetings of the PJM Board in a minute book to be kept for that purpose and shall perform like duties for the standing committees or special committees when required. He or she shall give, or cause to be given, notice of all special meetings of the PJM Board, and shall perform such other duties as may be prescribed by the PJM Board or President, under whose supervision he or she shall be. He or she shall have custody of the corporate seal of the LLC, and he or she, or an assistant secretary, shall have authority to affix the same to any instrument requiring it and, when so affixed, it may be attested by his or her signature or by the signature of such assistant secretary. The PJM Board may give general authority to any other officer to affix the seal of the LLC and to attest the affixing by his or her signature.

9.4 Treasurer.

The Treasurer shall have or arrange for the custody of the LLC's funds and securities and shall keep full and accurate accounts of receipts and disbursements in books belongings to the LLC and shall deposit all moneys and other valuable effects in the name and to the credit of the LLC in such depositories as may be designated by the PJM Board. The Treasurer shall disburse the funds of the LLC as may be ordered by the PJM Board, taking proper vouchers for such disbursements, and shall render to the President and PJM Board at its regular meetings, or when the PJM Board so requires, an account of his or her transactions as Treasurer and of the financial condition of the LLC. If required by the Board, the Treasurer shall give the LLC a bond (which shall be renewed periodically) in such sum and with such surety or sureties as shall be satisfactory to the PJM Board for the faithful performance of the duties of his office and of the restoration to the LLC, in case of his or her death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his or her possession or under his or her control belonging to the LLC.

9.5 Renewal of Officers; Vacancies.

Any officer elected or appointed by the PJM Board may be removed at any time by the affirmative vote of a majority of the PJM Board eligible to vote. Any vacancy occurring in any office of the LLC shall be filled by the PJM Board.

9.6 Compensation.

The salaries of all officers and agents of the LLC, and the reasonable compensation of the PJM Board, shall be fixed by the PJM Board.

10. OFFICE OF THE INTERCONNECTION

10.1 Establishment.

The Office of the Interconnection shall implement this Agreement, administer the PJM Tariff, and undertake such other responsibilities as set forth herein. All personnel of the Office of the Interconnection shall be employees of the LLC or under contract thereto. The cost of the Office of the Interconnection and expenses associated therewith, including salaries and expenses of said personnel, space and any necessary facilities or other capital expenditures, shall be recovered in accordance with Schedule 3. The Office of the Interconnection shall adopt, publish and comply with standards of conduct that satisfy the regulations of FERC.

10.2 Processes and Organization.

In order to carry out the responsibilities of the Office of the Interconnection for the safe and reliable operation of the PJM Region, the President may establish processes and organization for operating personnel and facilities as the President shall deem appropriate, and shall request such Members as the President shall deem appropriate to participate in such processes and organization. All such processes and organization shall be carried out in accordance with all applicable code of conduct or other functional separation requirements of FERC.

10.2.1 Financial Interests:

No Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, shall own, control or hold with power to vote Prohibited Securities subject to the following:

1. Each Office of the Interconnection Board Member, officer, or employee or spouse or dependent children thereof, shall divest of those Prohibited Securities within six (6) months of: (i) the time of his affiliation or employment with the Office of the Interconnection, (ii) the time a new Member is added to this Agreement, a new Eligible Customer begins taking service under the Tariff or a Nonincumbent Developer is pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6, where the Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof owns such Prohibited Securities; or (iii) the time of receipt of such Prohibited Securities (*e.g.* marriage, bequest, gift, etc.).

2. Nothing in this section 10.2.1 shall be interpreted to preclude a Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, from indirectly owning publicly traded Prohibited Securities through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted towards, or principally comprised of, entities in the electric industry or the electric utility industry, or any segments thereof) under which the Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, does not control the purchase or sale of such Prohibited Securities. Any such ownership, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.

3. Ownership of Prohibited Securities as part of a pension plan or fund of a Member, Eligible Customer or Nonincumbent Developer shall be permitted. Any such ownership, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.

4. Ownership of Prohibited Securities by a spouse of a Board Member, officer or employee of the Office of the Interconnection who is employed by a Member, Eligible Customer or Nonincumbent Developer and is required to purchase and maintain ownership of Securities of such Member, Eligible Customer or Nonincumbent Developer as a part of his or her employment shall be permitted. Any such ownership by a spouse, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.

5. A Board Member shall disclose to the PJM Board if the Board Member is aware that he or she, or an immediate family member, has a financial interest in a Member, Eligible Customer or Nonincumbent Developer, or their Affiliates that is subject to a matter before the PJM Board. The chair of the PJM Board Governance Committee and the Office of the

Interconnection legal counsel shall consult with the Board Member to determine whether the PJM Board Member should be recused from the PJM Board deliberations and decision making regarding the matter before the PJM Board.

10.3 Confidential Information.

The Office of the Interconnection shall comply with the requirements of Operating Agreement, section 18.17 with respect to any proprietary or confidential information received from or about any Member.

10.4 Duties and Responsibilities.

The Office of the Interconnection, under the direction of the President as supervised and overseen by the PJM Board, shall carry out the following duties and responsibilities, in accordance with the provisions of this Agreement:

i) Administer and implement this Agreement;

ii) Perform such functions in furtherance of this Agreement as the PJM Board, acting within the scope of its duties and responsibilities under this Agreement, may direct;

iii) Prepare, maintain, update and disseminate the PJM Manuals;

iv) Comply with NERC, and Applicable Regional Entity operation and planning standards, principles and guidelines;

v) Maintain an appropriately trained workforce, and such equipment and facilities, including computer hardware and software and backup power supplies, as necessary or appropriate to implement or administer this Agreement;

vi) Direct the operation and coordinate the maintenance of the facilities of the PJM Region used for both load and reactive supply, so as to maintain reliability of service and obtain the benefits of pooling and interchange consistent with this Agreement, and the Reliability Assurance Agreement;

vii) Direct the operation and coordinate the maintenance of the bulk power supply facilities of the PJM Region with such facilities and systems of others not party to this Agreement in accordance with agreements between the LLC and such other systems to secure reliability and continuity of service and other advantages of pooling on a regional basis;

viii) Perform interchange accounting and maintain records pertaining to the operation of the PJM Interchange Energy Market and the PJM Region;

ix) Notify the Members of the receipt of any application to become a Member, and of the action of the Office of the Interconnection on such application, including but not limited to the completion of integration of a new Member's system into the PJM Region, as specified in Operating Agreement, section 11.6(f);

x) Calculate the Weighted Interest and Default Allocation Assessment of each Member;

xi) Maintain accurate records of the sectors in which each Voting Member is entitled to vote, and calculate the results of any vote taken in the Members Committee;

xii) Furnish appropriate information and reports as are required to keep the Members regularly informed of the outlook for, the functioning of, and results achieved by the PJM Region;

xiii) File with FERC on behalf of the Members any amendments to this Agreement or the Schedules hereto, any new Schedules hereto, and make any other regulatory filings on behalf of the Members or the LLC necessary to implement this Agreement;

xiv) At the direction of the PJM Board, submit comments to regulatory authorities on matters pertinent to the PJM Region;

xv) Consult with the standing or other committees established pursuant to Operating Agreement, section 8.6 on matters within the responsibility of the committee;

xvi) Perform operating studies of the bulk power supply facilities of the PJM Region and make such recommendations and initiate such actions as may be necessary to maintain reliable operation of the PJM Region;

xvii) Accept, on behalf of the Members, notices served under this Agreement;

xviii) Perform those functions and undertake those responsibilities transferred to it under the Consolidated Transmission Owners Agreement including (A) directing the operation of the transmission facilities of the parties to the Consolidated Transmission Owners Agreement (B) administering the PJM Tariff, and (C) administering the Regional Transmission Expansion Planning Protocol set forth in Operating Agreement, Schedule 6;

xix) Perform those functions and undertake those responsibilities transferred to it under the Reliability Assurance Agreement, as specified in Operating Agreement, Schedule 8;

xx) Monitor the operation of the PJM Region, ensure that appropriate Emergency plans are in place and appropriate Emergency drills are conducted, declare the existence of an Emergency, and direct the operations of the Members as necessary to manage, alleviate or end an Emergency;

xxi) Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices;

xxii) Initiate such legal or regulatory proceedings as directed by the PJM Board to enforce the obligations of this Agreement; and

xxiii) Select an individual to serve as the Alternate Dispute Resolution Coordinator as specified in the PJM Dispute Resolution Procedures.

11. MEMBERS

11.1 Management Rights.

The Members or any of them shall not take part in the management of the business of, and shall not transact any business for, the LLC in their capacity as Members, nor shall they have power to sign for or to bind the LLC.

11.2 Other Activities.

Except as otherwise expressly provided herein, any Member may engage in or possess any interest in another business or venture of any nature and description, independently or with others, even if such activities compete directly with the business of the LLC, and neither the LLC nor any Member hereof shall have any rights in or to any such independent ventures or the income or profits derived therefrom.

11.3 Member Responsibilities.

11.3.1 General.

To facilitate and provide for the work of the Office of the Interconnection and of the several committees appointed by the Members Committee, each Member shall, to the extent applicable;

(a) Maintain complete and accurate records, if any, required to meet the purposes of this section and, subject to the provisions of this Agreement for the protection of the confidentiality of proprietary or commercially sensitive information, provide, as reasonably requested, data (excluding transactional data), documents, or records, to the Office of the Interconnection required for the following purposes: (i) maintenance of correct and updated Member and Affiliate Information, including appropriate personnel contacts, PJM committee representatives, organizational structure and other information as reasonably requested by the Office of the Interconnection to ensure the accuracy and completeness of Member records, (ii) maintenance of correct and updated Member and Affiliate Information on unit ownership, unit offer determination, unit offer submissions and unit operation, (iii) coordination of operations, (iv) accounting for all interchange transactions, (v) preparation of required reports, (vi) coordination of planning, including those data required for capacity accounting under the Reliability Assurance Agreement; (vii) preparation of maintenance schedules, (viii) analysis of system disturbances, and (ix) such other purposes, including those set forth in Operating Agreement, Schedule 2, as will contribute to the reliable and economic operation of the PJM Region and the administration by the Office of the Interconnection of the Agreement, the PJM Tariff and PJM Manuals – For the purposes of this subsection, Member and Affiliate Information means information regarding Members and either: (1) their direct and/or indirect subsidiaries subject to the jurisdiction of the FERC, or (2) their Related Parties;

(b) Provide such recording, telemetering, revenue quality metering, communication and control facilities as are required for the coordination of its operations with the Office of the Interconnection and those of the other Members and to enable the Office of the Interconnection to operate the PJM Region and otherwise implement and administer this Agreement, including equipment required in normal and Emergency operations and for the recording and analysis of system disturbances;

(c) Provide adequate and properly trained personnel to (i) permit participation in the coordinated operation of the PJM Region (ii) meet its obligation on a timely basis for supply of records and data, (iii) serve on committees and participate in their investigations, and (iv) share in the representation of the Interconnection in inter-regional and national reliability activities. Minimum training for Members that operate Market Operations Centers and local control centers shall include compliance with the applicable training standards and requirements in PJM Manual 40, Control Center Requirements, including the PJM System Operator Training Requirements in Attachment C;

(d) Share in the costs of committee activities and investigations (including costs of consultants, computer time and other appropriate items), communication facilities used by all the Members (in addition to those provided in the Office of the Interconnection), and such other expenses as are approved for payment by the PJM Board, such costs to be recovered as provided in Operating Agreement, Schedule 3;

(e) Comply with the requirements of the PJM Manuals and all directives of the Office of the Interconnection to take any action for the purpose of managing, alleviating or ending an Emergency, and authorize the Office of the Interconnection to direct the transfer or interruption of the delivery of energy on their behalf to meet an Emergency and to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, and be subject to the emergency procedure charges specified in Operating Agreement, Schedule 9 for any failure to follow the Emergency instructions of the Office of the Interconnection. In addressing any Emergency, the Office of the Interconnection shall comply with the terms of any reserve sharing agreements in effect for any part of the PJM Region.

11.3.2 Facilities Planning and Operation.

Consistent with and subject to the requirements of this Agreement, the PJM Tariff, the governing agreements of each Applicable Regional Entity, the Reliability Assurance Agreement, the Consolidated Transmission Owners Agreement, and the PJM Manuals, each Member shall cooperate with the other Members in the coordinated planning and operation of the facilities of its System within the PJM Region so as to obtain the greatest practicable degree of reliability, compatible economy and other advantages from such coordinated planning and operation. In furtherance of such cooperation each Member shall, as applicable:

(a) Consult with the other Members and the Office of the Interconnection, and coordinate the installation of its electric generation and Transmission Facilities with those of such other Members so as to maintain reliable service in the PJM Region;

(b) Coordinate with the other Members, the Office of the Interconnection and with others in the planning and operation of the regional facilities to secure a high level of reliability and continuity of service and other advantages;

(c) Cooperate with the other Members and the Office of the Interconnection in the implementation of all policies and procedures established pursuant to this Agreement for dealing with Emergencies, including but not limited to policies and procedures for maintaining or arranging for a portion of a Member's Generation Capacity Resources, at least equal to the applicable levels established from time to time by the Office of the Interconnection, to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

(d) Cooperate with the members of each Applicable Regional Entity to augment the reliability of the bulk power supply facilities of the region and comply with Applicable Regional Entities and NERC operating and planning standards, principles and guidelines and the PJM Manuals implementing such standards, principles and guidelines;

(e) Obtain or arrange for transmission service as appropriate to carry out this Agreement;

(f) Cooperate with the Office of the Interconnection's coordination of the operating and maintenance schedules of the Member's generating and Transmission Facilities with the facilities of other Members to maintain reliable service to its own customers and those of the other Members and to obtain economic efficiencies consistent therewith;

(g) Cooperate with the other Members and the Office of the Interconnection in the analysis, formulation and implementation of plans to prevent or eliminate conditions that impair the reliability of the PJM Region; and

(h) Adopt and apply standards adopted pursuant to this Agreement and conforming to NERC, and Applicable Regional Entity standards, principles and guidelines and the PJM Manuals, for system design, equipment ratings, operating practices and maintenance practices.

11.3.3 Electric Distributors.

In addition to any of the foregoing responsibilities that may be applicable, each Member that is an Electric Distributor, whether or not that Member votes in the Members Committee in the Electric Distributor sector or meets the eligibility requirements for any other sector of the Members Committee, shall:

(a) Accept, comply with or be compatible with all standards applicable within the PJM Region with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals, or be subject to an interconnected Member's requirements relating to the foregoing, so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region;

(b) Assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting automatically or manually with the Office of the Interconnection as it directs the operation of the PJM Region;

(c) Maintain or arrange for a portion of its connected load to be subject to control by automatic underfrequency, under-voltage, or other load-shedding devices at least equal to the levels established pursuant to the Reliability Assurance Agreement, or be subject to another Member's control for these purposes;

(d) Provide or arrange for sufficient reactive capability and voltage control facilities to conform to Good Utility Practice and (i) to meet the reactive requirements of its system and customers and (ii) to maintain adequate voltage levels and the stability required by the bulk power supply facilities of the PJM Region;

(e) Shed connected load, share Generation Capacity Resources and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in Emergencies;

(f) Maintain or arrange for a portion of its Generation Capacity Resources at least equal to the level established pursuant to the Reliability Assurance Agreement to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

(g) Provide or arrange through another Member for the services of a 24-hour local control center to coordinate with the Office of the Interconnection, each such control center to be furnished with appropriate telemetry equipment as specified in the PJM Manuals, and to be staffed by system operators trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner. In addition to meeting any training standards and requirements specified in this Agreement, local control center staff shall be required to meet applicable training standards and requirements in PJM Manual 40, Control Center Requirements, including the PJM System Operator Training Requirements in Attachment C;

(h) Provide to the Office of the Interconnection all System, accounting, customer tracking, load forecasting (including all load to be served from its System) and other data necessary or appropriate to implement or administer this Agreement, and the Reliability Assurance Agreement; and

(i) Comply with the underfrequency relay obligations and charges specified in Operating Agreement, Schedule 7.

11.3.4 Reports to the Office of the Interconnection.

Each Member shall report as promptly as possible to the Office of the Interconnection any changes in its operating practices and procedures relating to the reliability of the bulk power supply facilities of the PJM Region. The Office of the Interconnection shall review such reports, and if any change in an operating practice or procedure of the Member is not in accord with the established operating principles, practices and procedures for the PJM Region and such change adversely affects such region and regional reliability, it shall so inform such Member, and the other Members through their representative on the Operating Committee, and shall direct that such change be modified to conform to the established operating principles, practices and procedures.

11.4 Regional Transmission Expansion Planning Protocol.

The Members shall participate in regional transmission expansion planning in accordance with the Regional Transmission Expansion Planning Protocol set forth in Operating Agreement, Schedule 6.

11.5 Member Right to Petition.

(a) Nothing herein shall deprive any Member of the right to petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the petitioning Member believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any other Member (a) to oppose said proposal, or (b) to withdraw from the LLC pursuant to Operating Agreement, section 4.1.

(b) Nothing herein shall be construed as affecting in any way the right of the Members, acting pursuant to a vote of the Members Committee as specified in Operating Agreement, section 8.4, unilaterally to make an application to FERC for a change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, under section 205 of the Federal Power Act and pursuant to the rules and regulations promulgated by FERC thereunder, subject to the right of any Member that voted against such change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, in intervene in opposition to any such application.

11.6 Membership Requirements.

(a) To qualify as a Member, an Applicant shall:

(i) Be a Transmission Owner, a Generation Owner, an Other Supplier, an Electric Distributor, or an End-Use Customer;

(ii) Accept the obligations set forth in this Agreement;

(iii) Cure any default, including but not limited to paying all outstanding and unpaid obligations due to PJM and/or PJMSettlement by any former Member that is an Affiliate of the Applicant, if any, as required by PJM and/or PJMSettlement based on its evaluation of the membership application; and

(iv) Cure any default, including but not limited to paying all outstanding and unpaid obligations due to PJM and/or PJMSettlement by any former Member, and for which Applicant should be treated as the same Member that experienced the outstanding default, pursuant to the factors identified in Operating Agreement, Schedule 1, section 1.4.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.8, if any, as required by PJM and/or PJMSettlement based on its evaluation of the membership application.

(b) Certain Members that are Load Serving Entities are parties to the Reliability Assurance Agreement. Upon becoming a Member, any Applicant that is a Load Serving Entity in the PJM Region and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement.

(c) An Applicant that wishes to become a PJM Member and party to this Agreement shall apply, in writing, to the President of PJM setting forth its request, its qualifications for membership, its agreement to supply data and information as specified in this Agreement and any additional data or information reasonably requested by PJM and/or PJMSettlement, its agreement to pay all costs and expenses in accordance with Operating Agreement, Schedule 3, and providing all additional information specified pursuant to the Agreements for entities that wish to become Market Participants. Among other things, PJM will evaluate the application to determine whether the entity seeking to become a Member (i) is qualified for membership, (ii) satisfies the requirements for participation in one of the sectors in accordance with Operating Agreement, section 8.1, and/or (iii) presents any unreasonable, inherent or material risks to PJM, including but not limited to unreasonable credit risk pursuant to Tariff, Attachment Q that cannot be cured by posting Collateral or credit support commensurate with the risk of the anticipated market activity of the Applicant to the PJM Markets and PJM Members. Such review shall include an examination of whether the Applicant should be treated as a former Member that experienced an outstanding default in PJM, including but not limited to the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry, and other relevant factors. PJM and PJMSettlement will review applications to determine whether they satisfy applicable requirements. The determination whether an application for membership is approved shall be made within ninety (90) days after receipt of all documentation and information required by the Agreements and/or requested by PJM and/or PJMSettlement in the consideration of the application for membership. If an application for membership is not approved by the President of PJM, the Applicant will be provided a written notice explaining the basis for non-approval. An Applicant may appeal the non-approval of its application for membership to the Federal Energy Regulatory Commission.

(d) Nothing in Operating Agreement, section 11 is intended to remove, in any respect, the choice of participation by other utility companies or organizations in the operation of the PJM Region through inclusion in the System of a Member.

(e) An Applicant whose application is accepted by the President of PJM pursuant to section 11.6(c) above shall execute a supplement to this Agreement in substantially the form prescribed in Operating Agreement, Schedule 4, which supplement shall be countersigned by the President of PJM or the President's authorized designee. The Applicant shall become a Member effective on the date the supplement is countersigned by the President of PJM or the President's authorized designee.

(f) Applicants whose applications contemplate expansion or rearrangement of the PJM Region may become Members promptly as described in sections 11.6(c) and 11.6(e) above, but the integration of the Applicant's system into all of the operation and accounting provisions of the Agreements, shall occur only after completion of all required installations and modifications of metering, communications, computer programming, and other necessary and appropriate facilities and procedures, as determined by the Office of the Interconnection. The Office of the Interconnection shall notify the other Members when such integration has occurred.

(g) Applicants that become Members will be listed in Operating Agreement, Schedule 12.

(h) In accordance with this Agreement, Members agree that PJMSettlement shall be the Counterparty with respect to certain transactions under the PJM Tariff and this Agreement.

11.7 Associate Membership Requirements.

(a) If any of the following conditions apply, an entity may qualify as an Associate Member:

(i) The entity is not a member of the End-Use Customer sector and has not been a Market Participant over the past six months, and has no verifiable plans to become a Market Participant over the next six months;

(ii) The entity does not meet the requirements of Operating Agreement, section 11.6 ;

(b) The following rights and obligations shall apply to Associate Members:

(i) Associate Members shall pay the one half of the annual membership fee, and the application fee is waived;

(ii) Associate Members may participate in all stakeholder process activities;

(iii) Associate Members shall not vote in any stakeholder activities, working groups or committees;

(iv) Associate Members shall not participate in any of PJM's markets;

(v) Associate Members may become Members if they meet the requirements of a Member as defined in this Agreement;

(vi) Associate Members may participate in training offered by PJM at no cost;

(vii) Associate Members shall not be subject to default assessments pursuant to this Agreement.

12. TRANSFERS OF MEMBERSHIP INTEREST

The rights and obligations created by this Agreement shall inure to and bind the successors and assigns of such Member; provided, however, that the rights and obligations of any Member hereunder shall not be assigned without the approval of the Members Committee except as to a successor in operation of a Member's electric operating properties by reason of a merger, consolidation, reorganization, sale, spin-off, or foreclosure, as a result of which substantially all such electric operating properties are acquired by such a successor, and such successor becomes a Member.

13. INTERCHANGE

13.1 Interchange Arrangements with Non-Members.

Any Member may enter into interchange arrangements with others that are not Members with respect to the delivery or receipt of capacity and energy to fulfill its obligations hereunder or for any other purpose, subject to the standards and requirements established in or pursuant to this Agreement.

13.2 Energy Market.

The Office of the Interconnection shall administer an efficient energy market within the PJM Region, to be known as the PJM Interchange Energy Market, in which Members may buy and sell energy. The Office of the Interconnection will schedule in advance and dispatch generation on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by sellers within and into the PJM Region, continuing until sufficient generation is dispatched to serve the energy purchase requirements of such region and buyers out of such region, as well as the requirements of the PJM Region for ancillary services provided by such generation. Scheduling and dispatch shall be conducted in accordance with applicable schedules to the PJM Tariff and the Schedules to this Agreement.

14. METERING

14.1 Installation, Maintenance and Reading of Meters.

The quantities of electric energy involved in determination of the amounts of the billing rendered hereunder shall be ascertained by means of meters installed, maintained and read either at the expense of the party on whose premises the meters are located or as otherwise provided for by agreement between the parties concerned.

14.2 Metering Procedures.

Procedures with respect to maintenance, testing, calibrating, correction and registration records, and precision tolerance of all metering equipment shall be in accordance with Good Utility Practice. The expense of testing any meter shall be borne by the party owning such meter, except that when a meter tested upon request of another party is found to register within the established tolerance the party making the request shall bear the expense of such test.

14.3 Integrated Megawatt-Hours.

All metering of energy required herein shall be the integration of megawatt hours in the clock hour, and the quantities thus obtained shall constitute the megawatt load for such clock hour; provided, however, that adjustment shall be made for other contractual obligations of any Member as may be required to determine the quantity to be accounted for hereunder, and for transmission losses.

14.4 Meter Locations.

The meter locations to be used by the Members in determining their energy transactions on the PJM Region shall be as reasonably determined from time to time by the Member or the Office of the Interconnection.

14.5 Metering of Behind The Meter Generation.

Generating units, designated as Behind The Meter Generation, individually rated at ten megawatts or greater or that otherwise have been identified by the Office of the Interconnection as requiring metering for operational security reasons must have both revenue quality metering and telemetry equipment for operational security purposes. Multiple generating units, designated as Behind The Meter Generation, that are individually rated less than ten megawatts but together total more than ten megawatts and are identified by the Office of the Interconnection as requiring revenue quality metering and telemetry equipment may meet these metering requirements by being metered as a single unit.

14A. TRANSMISSION LOSSES

14A.1 Description of Transmission Losses.

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines and other transmission facilities.

14A.2 Inclusion of Transmission Losses.

Whenever in this Agreement, transmission losses are included in the determination of a charge, credit, load (including deviations), or demand reduction, it is explicitly so stated and such included losses shall be those losses incurred on all Transmission Facilities (to facilitate such calculation, Transmission Owners shall ensure that all such facilities are included in the PJM network model) and those losses incurred on generator step-up transformers that a Market Seller has not elected to remove from the loss calculation. Absent such explicit statement, such losses are not included in the determination.

14A.3 Other Losses.

Losses incurred on facilities other than those addressed in the preceding section may be included in the determination of charges, credits, load (including real-time deviations), or demand reductions as determined by electric distribution companies, unless this Agreement explicitly excludes such losses.

14B BILLING AND PAYMENT

14B.1 Billing Procedure:

PJMSettlement shall issue bills and billing statements pursuant to the provisions in this section 14B on behalf of itself and as agent for the Office of the Interconnection, as applicable. Payment of bills pursuant to this section 14B shall be made for the benefit of PJMSettlement and the Office of the Interconnection, as applicable.

(a) Monthly Bills. By the fifth Business Day of each month, PJM Settlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall issue a bill to Members and other entities for monthly activity and detailing the charges and credits for all services furnished under this Agreement, the PJM Tariff and any service or rate schedule during the preceding month (“billing month”), excluding amounts billed pursuant to weekly bills for activity during the preceding month.

(b) Weekly Bills. By 5:00 p.m. Eastern Prevailing Time each Tuesday (or Wednesday in the event that a Tuesday is a holiday), PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, will issue a weekly bill to Members and other entities for all activity for certain services furnished under this Agreement, the PJM Tariff and any service or rate schedule for the days of the billing month during the week ending the prior Wednesday. The services for which such weekly bills shall be issued are set forth in PJM Manual 29.

(c) Billing Statement. PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall provide Members and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Member’s or other entity’s activity during the billing month and amounts due, net of activity previously billed.

(d) Market Suspensions: For a Market Suspension that is less than or equal to 24 consecutive hours and where Day-ahead Prices and all data necessary to calculate the services is available in advance of the time needed for processing the bill, the timelines listed in subsections (a) and (b) shall apply. For all other Market Suspensions, billing activity as defined in subsection (b) will be included in a weekly bill that is issued at least five business days from the date on which PJM Settlement receives all data necessary to calculate the services included in the weekly bill for such Market Suspension. If there are no remaining weekly bills for the billing month associated with such Market Suspension, the billing activity as defined in subsection (b) will be billed in the next monthly bill that is issued at least five business days from the date on which PJM Settlement receives all data necessary to calculate the services. All other billing services for such Market Suspension will be billed within three calendar months after the calendar month that included such Market Suspension.

14B.2 Payments:

(a) Monthly Bills. Net amounts due to PJMSettlement, in its own name or as agent for the LLC, as applicable, pursuant to a monthly bill shall be due and payable by the Member or other entity no later than noon Eastern Prevailing Time on the due date of the first weekly bill issued for activity in the month that the monthly bill is issued. It is possible, due to the timing of holidays, that the billing and payment cycle for monthly bills stated here would call for payment of a monthly bill on a Friday that occurs less than three Business Days after the issuance of the bill by PJM. Where this occurs, the payment period of the monthly bill will be extended such that payment will be due when payment for the second weekly bill is due.

(b) Weekly Bills. Net amounts due to PJMSettlement, in its own name or as agent for the LLC, as applicable, pursuant to a weekly bill shall be due and payable by the Member or other entity no later than noon Eastern Prevailing Time on the third Business Day following the issuance of the weekly bill. Weekly bills issued after 5:00 p.m. Eastern Prevailing Time shall be considered to be issued the following Business Day.

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 14B.1 when due, the LLC may allow a municipal electric system to make arrangements with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

(a) the LLC determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;

(b) the municipal electric system reimburses PJM for the actual cost of such working capital;

(c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;

(d) PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 14B.1 above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 14B.2(a);

(e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

(f) the municipal electric system provides the LLC with at least one week of notice (though PJM may waive this provision), and;

(g) the accumulated duration of such postponed payments shall not exceed three months in a rolling twelve-month period.

PJM may terminate this payment option at any time it determines its excess working capital is no longer sufficient to allow further or continued extension financing. In such cases, PJM shall attempt to give five Business Days, but not less than three Business Days notice to the affected municipal electric system, and may call for immediate reimbursement of any outstanding amounts owed by the municipal electric system.

(c) Form of Payments. All payments tendered in satisfaction of a Member's or other entity's obligations to PJMSettlement or the LLC shall be made in the form of immediately available funds payable to PJMSettlement, or by wire transfer to a bank named by PJMSettlement.

(d) Payments by PJMSettlement. Unless delayed by unforeseen events, payments made by PJMSettlement, in its own name or as agent for the LLC, for amounts due to Members and other entities shall be paid no later than 5:00 p.m. Eastern Prevailing Time on the Business Day following the payment due date for net amounts owed to PJMSettlement, in its own name or as agent for the LLC, as specified above.

(e) Payment Calendar. A comprehensive billing and settlement calendar will be posted on the LLC's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

(f) Late Payments. In the event that a Member, or other entity, is delinquent in paying the amount set forth in its weekly or monthly bill two or more times within any rolling twelve (12) month period, PJMSettlement, in its own name or s agent for the LLC, may assess, in addition to the interest on each late payment as provided for in Section 7.2 of this Tariff, a late payment charge for a second and any subsequent failure to pay on time during such twelve (12) month period (a "Late Payment Charge"). The applicable Late Payment Charge will be assessed in an amount equal to the greater of: (i) two percent (2%) of the total amount set forth in the monthly or weekly bill that the Transmission Customer or other entity has been late in paying, or (ii) $1,000; up to a maximum of $100,000 per late bill payment. For the sole purpose of application of this Section 7.1A(f), weekly and monthly bills that are due on the same date shall be considered to be one bill; moreover, the term "on time" shall mean payment received on the date due; and "delinquent" shall mean any payment received on a day subsequent to the date due.

Late Payment Charges that are collected pursuant to this Section 7.1A(f) shall be credited to PJMSettlement administrative costs contemplated under Schedule 9 of this Tariff.

14B.3 Interest on Unpaid Balances:

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by PJMSettlement.

14B.4 Additional Billing and Payment Provisions With Respect to the Counterparty

(a) Each Member shall receive from PJMSettlement (and not from any other party), and shall pay to PJMSettlement (and not to any other party), the amounts specified in the PJM Tariff and this Agreement for services and transactions for which PJMSettlement is the Counterparty, and PJMSettlement shall be correspondingly obliged and entitled.

(b) **Payment netting.** If, during the settlement period, amounts in respect of obligations associated with transactions for which PJMSettlement are owed, and would otherwise be paid, by both a Member and PJMSettlement to each other, then the respective obligations to pay such amounts will automatically be cancelled and replaced by a single obligation upon the Member or PJMSettlement (as the case may be) that would have had to pay the larger aggregate amount to pay the net amount (if any) to the other.

(c) **Conditions for payment by the Counterparty.**

(i) A Member shall be entitled to payment from PJMSettlement during the settlement period if, and only if, during the settlement period there is no amount in default due and payable by that Member to PJMSettlement with respect to transactions for which PJMSettlement is a Counterparty and not paid or recovered and so long as an amount in default, or any part of it, remains owing to PJMSettlement, that Member will not request, demand or claim to be entitled to payment by PJMSettlement.

(ii) Subject to Operating Agreement, section 15, a defaulting Member shall be entitled to payment from PJMSettlement with respect to transactions for which PJMSettlement is the Counterparty, if, and only if, all amounts, liabilities and other obligations due, owing, incurred or payable by that defaulting Member to PJMSettlement or the LLC, whether those liabilities or obligations are actual or contingent, present or future, joint or several (including, without limitation, all interest (after as well as before judgment) and expenses) have been paid or recovered and until that time the defaulting Member will not request, demand or claim to be entitled to payment by PJMSettlement or the LLC.

(d) **Set-off.**

(i) If during the settlement period an amount is due and, but for Operating Agreement, section 14B.4(c), would have been payable from PJMSettlement to a Member, but before that settlement period there was due from that Member an amount in default (as defined in Operating Agreement, section 15) that has not been paid or recovered, then notwithstanding Operating Agreement, section 14B.4(c), the amount owing by PJMSettlement shall be automatically and unconditionally set off against the amount(s) in default.

(ii) If in respect of any non-paying Member there is more than one amount in default, then any amount due and payable from PJMSettlement shall be set off against the amounts in default in the order in which they originally became due and payable.

(e) **Liability of PJMSettlement.**

(i) The liability of PJMSettlement to make payments during the settlement period shall be limited so that the aggregate of such payments does not exceed the aggregate amount of payments that has been paid to or recovered by PJMSettlement, from Members (including by way of realization of financial security) in respect of that settlement period.

(ii) Where in relation to any settlement period, the aggregate amount that PJMSettlement pays to Members with respect to transactions for which PJMSettlement is the Counterparty is less than the amount to which those Members, but for the operation of section 14B(e)(i), would have been entitled: if and to the extent that, after the required time during the settlement period, PJMSettlement or the LLC is paid and recovers (including collection of such amount through Default Allocation Assessments) amounts from any Member, PJMSettlement shall to the extent of such receipts make payments (to certain Members) in accordance with the provisions of Operating Agreement, section 15.2.1.

15. ENFORCEMENT OF OBLIGATIONS

15.1 Failure to Meet Obligations.

15.1.1 Suspension and Termination of Market Participant Rights.

PJM may limit, suspend or terminate a Market Participant's right to participate in any PJM Market if it determines that the Market Participant does not continue to meet the obligations set forth in any of the Agreements, including but not limited to the obligation to be in compliance with the terms, or operating characteristics of any of its prior scheduled transactions in any market operated by PJM, the creditworthiness requirements set forth in Tariff, Attachment Q and/or the obligation to make timely payment, provided that PJM and/or PJMSettlement has notified the Market Participant of any such deficiency and afforded the Market Participant a reasonable opportunity to cure pursuant to section 15.1.5 below, or Tariff, Attachment Q, as applicable. PJM shall reinstate a Market Participant's right to participate in any PJM Market upon a determination by PJM and/or PJMSettlement that the Market Participant has, within the parameters of its opportunity to cure provided pursuant to section 15.1.5 below, or Tariff, Attachment Q, as applicable, satisfied the applicable requirements and is in compliance with the obligations set forth in the Agreements.

15.1.2 [Reserved for Future Use]

15.1.3 Payment of Bills.

Members and Participants shall make full and timely payment, in accordance with the terms specified by PJM, of all bills rendered in connection with or arising under or from any of the Agreements, any service or rate schedule, any tariff, or any services performed by PJM or transactions with PJMSettlement, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Member or Participant that fails to make full and timely payment to PJMSettlement (of amounts owed either directly to PJMSettlement or PJMSettlement as agent for PJM) or otherwise fails to meet its financial or other obligations to a Member, PJMSettlement, or PJM under any of the Agreements, shall, in addition to any requirement set forth in Operating Agreement, section 15.1 and upon expiration of the cure period specified in section 15.1.5 below, be in default.

15.1.4 Breach Notification and Remedy

If PJM or PJMSettlement concludes, upon its own initiative or the recommendation of or complaint by the Members Committee or any Member, that a Member or Participant is in breach of any of its obligation under any of the Agreements, including, but not limited to, the obligation to make timely payment and the obligation to meet PJM's creditworthiness standards and to otherwise comply with PJM's credit policies, PJM and/or PJMSettlement shall so notify such Member or Participant. The notified Member or Participant may remedy such asserted breach by: (i) paying all amounts assertedly due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); and (ii) demonstration to the satisfaction of PJM and/or PJMSettlement that the Member or Participant has taken appropriate measures to meet any other obligation of which it was deemed to be in breach; provided, however, that any such payment or demonstration may be subject to a reservation of rights, if any, to subject such matter to the PJM Dispute Resolution Procedures; and provided, further, that any such determination by PJM and/or PJMSettlement may be subject to review by the PJM Board upon request of the Member or Participant involved or PJM and/or PJMSettlement.

15.1.5 Default Notification and Remedy

If a Member or Participant has not remedied a breach, as described in section 15.1.4 above, by 4:00 p.m. Eastern Prevailing Time on the first Business Day following PJM's or PJMSettlement's issuance of a written notice of breach or Collateral Call, the notice of which is issued before 1:00 p.m. Eastern Prevailing Time, or by 4:00 p.m. Eastern Prevailing Time on the second Business Day following PJM's or PJMSettlement's issuance to the Member or Participant of a written notice of breach or Collateral Call, the notice of which is issued at or after 1:00 p.m. Eastern Prevailing Time, or receipt of the PJM Board's decision on review, if applicable, then the Member or Participant shall be in default and, in addition to such other remedies as may be available to PJM or PJMSettlement:

i) A defaulting Market Participant may be precluded from buying or selling in any market operated by PJM until the default is remedied as set forth above;

ii) A defaulting Member shall not be entitled to participate in the activities of any committee or other body established by the Members Committee or PJM; and

iii) A defaulting Member shall not be entitled to vote on the Members Committee or any other committee or other body established pursuant to this Agreement.

iv) PJM shall notify all other Members of the default.

v) The Financial Transmission Rights positions of a Member in default shall be addressed as provided in Operating Agreement, Schedule 1, section 7.3.9 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.3.9.

vi) PJM may permit a defaulting Market Participant to continue to participate in PJM Markets: (a) in support of grid reliability, (b) when such Market Participant is a net market seller, (c) when such Market Participant has the ability to post collateral, or (d) to enable certain customers to continue to receive service prior to PJM receiving regulatory and or legal approval to terminate.

15.1.6 Reinstatement of Member Following Default and Remedy

a. A Member that has been declared in default, solely of PJM's and PJMSettlement's creditworthiness standards, or fails to otherwise comply with PJM's credit policies as more fully described in Tariff, Attachment Q, once within any 12 month period may be reinstated in full after remedying such default and satisfying any requirements imposed upon the Member as a result of the default.

b. A Member that has been declared in default of any of the Agreements for failing to: (i) make timely payments when due once during any prior 12 month period, or (ii) adhere to PJM's creditworthiness standards and credit policies, twice during any prior 12 month period, may be subject to the following restrictions:

a) Loss of stakeholder privileges, including voting privileges, for 12 months following such default; and

b) Loss of the allowance of unsecured credit for 12 months following such default

c. A Member that has been declared in default of this Agreement for failing to: (i) make timely payments when due twice during any prior 12 month period, or (ii) adhere to PJM's creditworthiness standards and credit policies, three times during any prior 12 month period, shall, except as provided for in section 15.1.6(d) below, not be eligible to be reinstated as a Member to this Agreement and its membership rights pursuant to this Agreement shall be terminated in accordance with Operating Agreement, section 4.1(c), notwithstanding whether such default has been remedied. Furthermore:

a) PJM and PJMSettlement shall address all of the Member's current and forward positions in accordance with the provisions of this Agreement and the PJM Tariff; and

b) A Member terminated in accordance with these provisions shall be precluded from seeking future membership in PJM under this Agreement whether in the name of the Member when it was terminated from PJM membership or as a new Applicant under a different name, affiliation, or organization if the Member or new Applicant experienced a previous default that resulted in a loss to the PJM Markets and was terminated from membership. Whether an Applicant should be considered the same as a Member that previously defaulted will be determined based on the factors identified in Operating Agreement, Schedule 1, section 1.4.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.8.

d. A Member may appeal a determination made pursuant to the foregoing procedures utilizing PJM's Dispute Resolution Procedures as set forth in Operating Agreement, Schedule 5, (provided, however, that a Member's decision to utilize these procedures shall not operate to stay the ability of PJM to exercise any and all of its rights under this Agreement and the PJM Tariff) and may be reinstated provided that the Member can demonstrate the following:

a) that it has otherwise consistently complied with its obligations under this Agreement and the PJM Tariff; and

b) the failure to comply was not material; and

c) the failure to comply was due in large part to conditions that were not in the common course of business.

15.1.7 Allocation of Costs and Proceeds Resulting from Addressing Defaulting Member Financial Transmission Rights Positions.

Addressing a defaulting Member's Financial Transmission Rights positions pursuant to Operating Agreement, Schedule 1, section 7.3.9, and Tariff, Attachment K-Appendix, section 7.3.9, shall result in a final settlement amount. The final settlement amount may be aggregated with any other amounts owed by the defaulting Member to PJM and/or PJMSettlement and may be set off by PJM and/or PJMSettlement against any amounts owed by PJM and/or PJMSettlement to the defaulting Member for purposes of determining the Default Allocation Assessment pursuant to the provisions of section 15.2.2 below. Any payments made to a Member purchasing some or all of a liquidated Financial Transmission Rights portfolio shall be net of that Member's charge resulting from a Default Allocation Assessment.

15.2 Enforcement of Obligations.

If PJM sends a notice to the PJM Board that a Member has failed to perform an obligation under any of the Agreements, the PJM Board, on behalf of PJM and PJMSettlement, shall initiate such action against such Member to enforce such obligation as the PJM Board shall deem appropriate. Subject to the procedures specified in section 15.1 above, a Member's failure to perform such obligation shall be deemed to be a default under this Agreement. In order to remedy a default, but without limiting any rights PJM or PJMSettlement may have against the defaulting Member, the PJM Board may assess against, and collect from, the Members not in default, in proportion to their Default Allocation Assessment, an amount equal to the amount that the defaulting Member has failed to pay to PJMSettlement or PJM (less amounts covered by Collateral, held by PJMSettlement, on behalf of itself and as agent for PJM, or indemnifications paid to PJM or PJMSettlement), along with appropriate interest. Such assessment shall in no way relieve the defaulting Member of its obligations. In addition to any amounts in default, the defaulting Member shall be liable to PJM and PJMSettlement for all reasonable costs incurred in enforcing the defaulting Member's obligations.

15.2.1 Collection by PJM.

PJM and PJMSettlement are authorized to pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims on behalf of the affected Members in the state and federal courts as well as under the United States Bankruptcy Code. Prior to initiating formal legal action in state or federal court to pursue collection, PJM and PJMSettlement shall provide to the Members Committee an explanation of its intended action. Upon the duly seconded motion of any Member, the Members Committee may conduct a vote to afford PJM and PJMSettlement a sense of the membership as regards to PJM's or PJMSettlement's intended action to pursue collection. PJM and PJMSettlement shall consider any such vote before initiating formal legal action and at all times during the course of any collection effort evaluate the expected benefits in pursuing such effort in light of any changed circumstances. After deducting the costs of collection, any amounts recovered by PJM and PJMSettlement shall be distributed to the Members who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Member.

15.2.2 Default Allocation Assessment.

(a) "Default Allocation Assessment" shall be equal to (0.1(1/N) + 0.9(A/Z)), where:

N = the total number of Members, calculated as of five o'clock p.m. eastern prevailing time on the date PJM declares a Member in default, excluding ex officio Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under Operating Agreement, section 17.2.

A = for Members comprising factor "N" above, the Member's gross activity as determined by summing the absolute values of the charges and credits for each of the Activity

Line Items identified in section 15.2.2(b) below as accounted for and billed pursuant to Operating Agreement, Schedule 1, section 3 for the month of default and the two previous months.

Z = the sum of factor A for all Members excluding ex officio Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under Operating Agreement, section 17.2.

The assessment value of (0.1(1/N)) shall not exceed $10,000 per Member per calendar year, cumulative of all defaults, or more than once per Member default if Default Allocation Assessment charges for a single Member default span multiple calendar years. For this purpose, a default by an individual Member that spans multiple billing periods without cure shall be considered a single default. If one or more defaults arise that cause the value to exceed $10,000 per Member, then the excess shall be reallocated through the gross activity factor.

(b) Activity Line Items shall be each of the line items on the PJM monthly bills net of load reconciliation adjustments and adjustments applicable to activity for the current billing month appearing on the same bill.

15.3 Obligations to a Member or Participant in Default.

The Members have no continuing obligation to provide the benefits of interconnected operations to a Member or Participant in default.

15.4 Obligations of a Member or Participant in Default.

A Member or Participant found to be in default shall take all possible measures to mitigate the continued impact of the default on the Members not in default, including, but not limited to, loading its own generation to supply its own load to the maximum extent possible.

15.5 No Implied Waiver.

A failure of a Member, the PJM Board, PJMSettlement, or PJM to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such entity's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

15.6 Limitation on Claims.

No adjustment in the billing for any service, transaction, or charge under this Agreement may be asserted by PJM, PJMSettlement, or any Member or Participant with respect to a month, if more than two years has elapsed since the first date upon which the billing for that month occurred. PJMSettlement, on behalf of itself or as agent for PJM, may make no adjustment to a Member's or Participant's bill with respect to a month for any service, transaction, or charge under this Agreement, if more than two years have elapsed since the first date upon which the billing for that month occurred, unless 1) a claim made by a Member or Participant in writing and addressed to the President of PJMSettlement seeking such adjustment has been received by PJMSettlement prior thereto or 2) PJM and/or PJMSettlement have notified the Member or Participant in writing of the need to make such an adjustment prior thereto.

16. LIABILITY AND INDEMNITY

16.1 Members.

(a) As between the Members, except as may be otherwise agreed upon between individual Members with respect to specified interconnections, each Member will indemnify and hold harmless each of the other Members, and its directors, officers, employees, agents, or representatives, of and from any and all damages, losses, claims, demands, suits, recoveries, costs and expenses (including all court costs and reasonable attorneys' fees), caused by reason of bodily injury, death or damage to property of any third party, resulting from or attributable to the fault, negligence or willful misconduct of such Member, its directors, officers, employees, agents, or representatives, or resulting from, arising out of, or in any way connected with the performance of its obligations under this Agreement, excepting only, and to the extent, such cost, expense, damage, liability or loss may be caused by the fault, negligence or willful misconduct of any other Member. The duty to indemnify under this Agreement will continue in full force and effect notwithstanding the expiration or termination of this Agreement or the withdrawal of a Member from this Agreement, with respect to any loss, liability, damage or other expense based on facts or conditions which occurred prior to such termination or withdrawal.

(b) The amount of any indemnity payment arising hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Member seeking indemnification in respect of the indemnified action, claim, demand, costs, damage or liability. If any Member shall have received an indemnity payment for an action, claim, demand, cost, damage or liability and shall subsequently actually receive insurance proceeds or other amounts for such action, claim, demand, cost, damage or liability, then such Member shall pay to the Member that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

16.2 LLC Indemnified Parties.

(a) The LLC will indemnify and hold harmless the PJM Board, the LLC's officers, employees and agents, and any representatives of the Members serving on the Members Committee and any other committee created under Operating Agreement, section 8 (all such Board Members, officers, employees, agents and representatives for purposes of Operating Agreement, section 16 being referred to as "LLC Indemnified Parties"), of and from any and all actions, claims, demands, costs (including consequential or indirect damages, economic losses and all court costs and reasonable attorneys' fees) and liabilities to any third parties, arising from, or in any way connected with, the performance of the LLC under this Agreement, or the fact that such LLC Indemnified Party was serving in such capacity, except to the extent that such action, claim, demand, cost or liability results from the willful misconduct of any LLC Indemnified Party with respect to participation in the misconduct. To the extent any dispute arises between any Member and the LLC arising from, or in any way connected with, the performance of the LLC under this Agreement, the Member and the LLC shall follow the PJM Dispute Resolution Procedures. To the extent that any such action, claim, demand, cost or liability arises from a Member's contractual or other obligation to provide electric service directly or indirectly to said third party, which obligation to provide service is limited by the terms of any tariff, service agreement, franchise, statute, regulatory requirement, court decision or other limiting provision, the Member designates the LLC and each LLC Indemnified Party a beneficiary of said limitation.

(b) An LLC Indemnified Party shall not be personally liable for monetary damages for any breach of fiduciary duty by such LLC Indemnified Party, except that an LLC Indemnified Party shall be liable to the extent provided by applicable law (i) for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law, or (ii) for any transaction from which the LLC Indemnified Party derived an improper personal benefit. Notwithstanding (i) and (ii), indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the LLC if and to the extent that the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses that such court shall deem proper. If applicable law is hereafter construed or amended to authorize the further elimination or limitation of the liability of LLC Indemnified Parties, then the liability of the LLC Indemnified Parties, in addition to the limitation on personal liability provided herein, shall be limited to the fullest extent permitted by law. No amendment to or repeal of this section shall apply to or have any effect on the liability or alleged liability of any LLC Indemnified Party or with respect to any acts or omissions occurring prior to such amendment or repeal. The termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which such person reasonably believed to be in or not opposed to the best interests of the LLC, and with respect to any criminal action or proceeding, had reasonable cause to believe that his or her conduct was unlawful.

(c) The LLC may pay expenses incurred by an LLC Indemnified Party in defending a civil, criminal, administrative or investigative action, suit or proceeding in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of such LLC Indemnified Party to repay such amount if it shall ultimately be determined that such LLC Indemnified Party is not entitled to be indemnified by the LLC as authorized in this Section.

(d) In the event the LLC incurs liability under this section 16.2 that is not adequately covered by insurance, such amounts shall be recovered pursuant to the PJM Tariff as provided in Operating Agreement, Schedule 3.

16.3 Workers Compensation Claims.

Each Member shall be solely responsible for all claims of its own employees, agents and servants growing out of any Workers' Compensation Law.

16.4 Limitation of Liability.

No Member or its directors, officers, employees, agents, or representatives shall be liable to any other Member or its directors, officers, employees, agents, or representatives, whether liability arises out of contract, tort (including negligence), strict liability, or any other cause of or form of action whatsoever, for any indirect, incidental, consequential, special or punitive cost, expense, damage or loss, including but not limited to loss of profits or revenues, cost of capital of financing, loss of goodwill or cost of replacement power, arising from such Member's performance or failure to perform any of its obligations under this Agreement or the ownership, maintenance or operation of its System; provided, however, that nothing herein shall be deemed to reduce or limit the obligations of any Member with respect to the claims of persons or entities that are not parties to this Agreement.

16.5 Resolution of Disputes.

To the extent any dispute arises between one or more Members regarding any issue covered by this Agreement, the Members shall follow the dispute resolution procedures set forth in the PJM Dispute Resolution Procedures.

16.6 Gross Negligence or Willful Misconduct.

Neither PJMSettlement, the LLC, nor the LLC Indemnified Parties shall be liable to the Members or any of them, or to any third party or other person, for any claims, demands or costs arising from, or in any way connected with, the performance of PJMSettlement or the LLC under this Agreement other than actions, claims or demands based on gross negligence or willful misconduct; provided, however, that nothing herein shall limit or reduce the obligations of PJMSettlement or the LLC to the Members or any of them under the express terms of this Agreement or the PJM Tariff, including, but not limited to, those set forth in Operating Agreement, section 6.2 and Operating Agreement, section 6.3.

16.7 Insurance.

The PJM Board shall be authorized to procure insurance against the risks borne by the LLC and the LLC Indemnified Parties, the cost of which shall be treated as a cost and expense of the LLC.

17. MEMBER REPRESENTATIONS, WARRANTIES AND COVENANTS

17.1 Representations and Warranties.

Each Member makes the following representations and warranties to the LLC and each other Member, as of the Effective Date or such later date as such Member shall become admitted as a Member of the LLC.

17.1.1 Organization and Existence.

Such Member is an entity duly organized, validly existing and in good standing under the laws of the state of its organization.

17.1.2 Power and Authority.

Such Member has the full power and authority to execute, deliver and perform this Agreement and to carry out the transactions contemplated hereby.

17.1.3 Authorization and Enforceability.

The execution and delivery of this Agreement by such Member and the performance of its obligations hereunder have been duly authorized by all requisite action on the part of the Member, and do not conflict with any applicable law or with any other agreement binding upon the Member. The Agreement has been duly executed and delivered by such Member and constitutes the legal, valid and binding obligation of such Member, enforceable against it in accordance with the terms thereof, except insofar as such enforceability may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditors' rights generally, and to general principles of equity whether such principles are considered in proceedings in law or in equity.

17.1.4 No Government Consents.

No authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing with, any governmental authority is required for the execution, delivery and performance by such Member of this Agreement or the carrying out by such Member of the transactions contemplated hereby other than such authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing that is pending before such governmental authority.

17.1.5 No Conflict or Breach.

None of the execution, delivery and performance by such Member of this Agreement, the compliance with the terms and provisions hereof and the carrying out of the transactions contemplated hereby, conflicts or will conflict with or will result in a breach or violation of any of the terms, conditions or provisions of any law, governmental rule or regulation or the charter documents or bylaws of such Member or any applicable order, writ, injunction, judgment or decree of any court or governmental authority against such Member or by which it or any of its properties, is bound, or any loan agreement, indenture, mortgage, bond, note, resolution, contract or other agreement or instrument to which such Member is a party or by which it or any of its properties is bound, or constitutes or will constitute a default thereunder or will result in the imposition of any lien upon any of its properties.

17.1.6 No Proceedings.

There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Member, threatened against the Member before any federal, state, foreign or local court, tribunal or government agency or authority that might materially delay, prevent or hinder the performance by the Member of its obligations hereunder.

17.2 Municipal Electric Systems.

Any provisions of Operating Agreement, section 17.1 notwithstanding, if any Member that is a municipal electric system believes in good faith that the provisions of Operating Agreement, section 5.1(b) and Operating Agreement, section 16.1 may not lawfully be applied to that Member under applicable state law governing municipal activities, the Member may request a waiver of the pertinent provisions of the Agreement. Any such request for waiver shall be supported by an opinion of counsel for the Member to the effect that the provision of the Agreement as to which waiver is sought may not lawfully be applied to the Member under applicable state law. The PJM Board shall have the right to have the opinion of the Member's counsel reviewed by counsel to the LLC. If the PJM Board concludes that either or both of Operating Agreement, section 5.1(b) and Operating Agreement, section 16.1 may not lawfully be applied to a municipal electric system Member, it shall waive the application of the affected provision or provisions to such municipal Member. Any Member not permitted by law to indemnify the other Members shall not be indemnified by the other Members.

17.3 Survival.

All representations and warranties contained in this Section 17 shall survive the execution and delivery of this Agreement.

18. MISCELLANEOUS PROVISIONS

18.1 [Reserved.]

18.2 Fiscal and Taxable Year.

The fiscal year and taxable year of the LLC shall be the calendar year.

18.3 Reports.

Each year prior to the Annual Meeting of the Members, the PJM Board shall cause to be prepared and distributed to the Members a report of the LLC's activities since the prior report.

18.4 Bank Accounts; Checks, Notes and Drafts.

(a) Funds of the LLC shall be deposited in an account or accounts of a type, in form and name and in a bank(s) or other financial institution(s) which are participants in federal insurance programs as selected by the PJM Board. The PJM Board shall arrange for the appropriate conduct of such accounts. Funds may be withdrawn from such accounts only for bona fide and legitimate LLC purposes and may from time to time be invested in such short-term securities, money market funds, certificates of deposit or other liquid assets as the PJM Board deems appropriate. All checks or demands for money and notes of the LLC shall be signed by any officer or by any other person designated by the PJM Board.

(b) The Members acknowledge that the PJM Board may maintain LLC funds in accounts, money market funds, certificates of deposit, other liquid assets in excess of the insurance provided by the Federal Deposit Insurance Corporation, or other depository insurance institutions and that the PJM Board shall not be accountable or liable for any loss of such funds resulting from failure or insolvency of the depository institution.

(c) Checks, notes, drafts and other orders for the payment of money shall be signed by such persons as the PJM Board from time to time may authorize. When the PJM Board so authorizes, the signature of any such person may be a facsimile.

18.5 Books and Records.

(a) At all times during the term of the LLC, the PJM Board shall keep, or cause to be kept, full and accurate books of account, records and supporting documents, which shall reflect, completely, accurately and in reasonable detail, each transaction of the LLC. The books of account shall be maintained and tax returns prepared and filed on the method of accounting determined by the PJM Board. The books of account, records and all documents and other writings of the LLC shall be kept and maintained at the principal office of the Interconnection.

(b) The PJM Board shall cause the Office of the Interconnection to keep at its principal office the following:

i) A current list in alphabetical order of the full name and last known business address of each Member and the Members Committee sector of each Voting Member;

ii) A copy of the Certificate of Formation and the Certificate of Conversion, and all Certificates of Amendment thereto;

iii) Copies of the LLC's federal, state, and local income tax returns and reports, if any, for the three most recent years; and

iv) Copies of the Operating Agreement, as amended, and of any financial statements of the LLC for the three most recent years.

18.6 Amendment.

(a) Except as provided by law or otherwise set forth herein, this Agreement, including any Schedule hereto, may be amended, or a new Schedule may be created, only upon: (i) submission of the proposed amendment to the PJM Board for its review and comments; (ii) approval of the amendment or new Schedule by the Members Committee, after consideration of the comments of the PJM Board, in accordance with Operating Agreement, section 8.4, or written agreement to an amendment of all Members not in default at the time the amendment is agreed upon; and (iii) approval and/or acceptance for filing of the amendment by FERC and any other regulatory body with jurisdiction thereof as may be required by law. If and as necessary, the Members Committee may file with FERC or other regulatory body of competent jurisdiction any amendment to this Agreement or to its Schedules or a new Schedule not filed by the Office of the Interconnection.

(b) Notwithstanding the foregoing, an applicant eligible to become a Member in accordance with the procedures specified in this Agreement shall become a Member by executing a counterpart of this Agreement without the need for amendment of this Agreement or execution of such counterpart by any other Member.

(c) Each of the following fundamental changes to the LLC shall require or be deemed to require an amendment to this Agreement and shall require the prior approval of FERC:

i) Adoption of any plan of merger or consolidation;

ii) Adoption of any plan of sale, lease or exchange of assets relating to all, or substantially all, of the property and assets of the LLC;

iii) Adoption of any plan of division relating to the division of the LLC into two or more corporations or other legal entities;

iv) Adoption of any plan relating to the conversion of the LLC into a stock corporation;

v) Adoption of any proposal of voluntary dissolution; or

vi) Taking any action which has the purpose or effect of the adoption of any plan or proposal described in items (i), (ii), (iii), (iv) or (v) above.

18.7 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.8 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

18.9 Catastrophic Force Majeure.

Performance of any obligation arising under this Agreement, owed by a Member to either PJM or to another Member (either directly or indirectly), shall not be excused or suspended by reason of an event of force majeure unless such event constitutes an event of Catastrophic Force Majeure. An event of Catastrophic Force Majeure shall excuse a Member from performing obligations arising under this Agreement during the period such Member's performance is prevented by any event of Catastrophic Force Majeure, provided such event was not caused by such Member's fault or negligence. An event of Catastrophic Force Majeure may suspend but shall not excuse any payment obligation owed by a Member. Any excuse or exception to a performance obligation expressly provided for by specific terms of this Agreement, the PJM Tariff, or the Reliability Assurance Agreement shall apply according to their terms and remain in full force and effect without regard to this provision. Unless expressly referenced in any section of this Agreement, the PJM Tariff, or the Reliability Assurance Agreement, this provision shall not apply, and not supersede, other force majeure provisions that are expressly applicable to specific obligations arising under any sections of those documents. This provision shall apply in its entirety to all rules, rights and obligations specified in Tariff, Attachment K-Appendix, Tariff, Attachment DD, Operating Agreement, Schedule 1, and the Reliability Assurance Agreement. Other than this provision, no other force majeure provisions in this Agreement, the PJM Tariff, or the Reliability Assurance Agreement shall apply in any manner to Tariff, Attachment K-Appendix, Tariff, Attachment DD, Operating Agreement, Schedule 1, and the Reliability Assurance Agreement.

18.10 Further Assurances.

Each Member hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

18.11 Seal.

The seal of the LLC shall have inscribed thereon the name of the LLC, the year of its organization and the words "Corporate Seal, Delaware." The seal may be used by causing it or a facsimile thereof to be impressed or affixed or reproduced or otherwise.

18.12 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

18.13 Costs of Meetings.

Each Member shall be responsible for all costs of its representative, alternate or substitute in attending any meeting. The Office of the Interconnection shall pay the other reasonable costs of meetings of the PJM Board and the Members Committee, and such other committees, subcommittees, task forces, working groups, User Groups or other bodies as determined to be appropriate by the Office of the Interconnection, which costs otherwise shall be paid by the Members attending. The Office of the Interconnection shall reimburse all Board Members for their reasonable costs of attending meetings.

18.14 Notice.

(a) Except as otherwise expressly provided herein, notices required under this Agreement shall be in writing and shall be sent to a Member by overnight courier, hand delivery, telecopier or other reliable electronic means to the representative on the Members Committee of such Member at the address for such Member previously provided by such Member to the Office of the Interconnection. Any such notice so sent shall be deemed to have been given (i) upon delivery if given by overnight couriers or hand delivery, or (ii) upon confirmation if given by telecopier or other reliable electronic means. Notices of meetings of the Members Committee or committees, subcommittees, task forces, working groups and other bodies under its auspices may be given as provided in the Members Committee by-laws.

(b) Notices, as well as copies of the agenda and minutes of all meetings of committees, subcommittees, task forces, working groups, User Groups, or other bodies formed under this Agreement, shall be posted in a timely fashion on and made available for downloading from the PJM website.

18.15 Headings.

The section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

18.16 No Third-Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Members and their respective successors and permitted assigns and, unless expressly stated herein, is not intended to and shall not confer any rights or benefits on any third party (other than successors and permitted assigns) not a signatory hereto.

18.17 Confidentiality.

18.17.1 Party Access.

(a) No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection and/or the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

(b) Except as may be provided in this Agreement or in the PJM Open Access Transmission Tariff, the Office of the Interconnection shall not disclose to its Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Office of the Interconnection or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Office of the Interconnection from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality; provided further that nothing contained herein shall prohibit the Office of the Interconnection from providing Member confidential information to the NERC, EIDSN, Inc., any Applicable Regional Entity, any Reliability Coordinator, any Transmission Operator, and the agents, representatives, or contractors of such entity, to the extent that (i) the Office of the Interconnection determines in its reasonable discretion that the exchange of such information is required to enhance and/or maintain reliability within the Members' Applicable Regional Entities and their neighboring Regional Entities, or within the region of any Reliability Coordinator, (ii) such entity is bound by a written agreement to maintain such confidentiality, and (iii) the Office of the Interconnection has notified the affected party of its intention to release such information no less than five Business Days prior to the release. The Office of the Interconnection, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section 18.17. Nothing contained herein shall prohibit the Office of the Interconnection or its designated agents, representatives, or contractors from providing to another Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such RTO or ISO has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such RTO or ISO is bound by a tariff provision requiring that the e-Tag data be maintained as confidential or, in the absence of a tariff requirement governing confidentiality, a written agreement with the Office of the Interconnection consistent with FERC Order No. 771 and any clarifying orders and implementing regulations. The Office of the Interconnection shall collect and use confidential information only in connection with its authority under this Agreement and the Open Access Transmission Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

(c) Nothing contained herein shall prevent the Office of the Interconnection from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Office of the Interconnection and/or the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Office of the Interconnection shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Office of the Interconnection, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

(d) Reciprocal provisions to this section 18.17.1, Operating Agreement, section18.17.2, Operating Agreement, section 18.17.3, Operating Agreement, section18.17.4 and Operating Agreement, section 18.17.5 , delineating the confidentiality requirements of PJM's Market Monitoring Unit, are set forth in Tariff, Attachment M – Appendix, section I.

(e) Notwithstanding anything to the contrary in this Agreement or in the PJM Tariff, the Office of the Interconnection shall post the following on its website:

(i) the non-aggregated bid data and Offer Data submitted by Market Participants (for participation on the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719. However, to protect the confidential, market sensitive and/or proprietary bidding strategies of Market Participants as well as the identity of Market Participants from being discernible from the published data, the posted information will not reveal the (a) name of the resource, (b) characteristics of a specific resource, (c) identity of the load, (d) name of the individual or entity submitting the data, (e) identity of the resource owner, or (f) location of the resource at a level lower than its Zone. The Office of the Interconnection also reserves the right to take any other precautionary measures that it deems appropriate to preserve the confidential, market sensitive and/or proprietary bidding strategies of Market Participants to the extent not specifically set forth herein.

(ii) Within 20 calendar days after the end of each month, (a) the total daily uplift credits by Zone as set forth in Tariff, Attachment J, and RAA, Schedule 15, and applicable uplift charge codes (including lost opportunity cost contained within operating reserves) and (b) the total daily uplift charges by applicable PJM Region or Zone, as set forth in Tariff, Attachment J and RAA, Schedule 15, and applicable uplift charge codes along with relevant subcategories by which they are allocated. The Office of the Interconnection shall incorporate the best available information at the time the posting is created.

(iii) Within 90 calendar days after the end of each month, the name of each generation resource unit and amount of uplift credit payments by applicable uplift charge codes (including lost opportunity cost contained within operating reserves, but excluding Black Start Service) for each resource unit that received uplift credits in that month. For Demand Resources or Economic Load Response Participants, the Office of Interconnection shall post, within 90 calendar days after the end of each month, the individual resource identification number associated with the Demand Resource or Economic Load Response Participant's relevant dispatch group or registration, the name of the associated Curtailment Service Provider, the Zone and energy pricing point used to settle the Demand Resource or Economic Load Response Participant's dispatch group or registration, and the corresponding amount of uplift credits by applicable uplift charge codes for the dispatch group or registration that received uplift credits in that month. The Office of Interconnection shall incorporate the best available information at the time the posting is created.

(iv) Within 30 calendar days after the end of each month, each Operator-initiated Commitment listing the size of the commitment in megawatts (where megawatts are equal to the economic maximum), Zone (as set forth in Tariff, Attachment J and RAA, Schedule 15), commitment reason, and commitment start time. Commitment reasons shall include, but are not limited to, system wide capacity, constraint management, and voltage support.

(f) To the extent permitted pursuant to 18 C.F.R. §38.2 (or successor provisions), nothing contained herein shall prohibit the Office of the Interconnection from sharing non-public, operational information with an interstate natural gas pipeline operator for the purpose of promoting reliable service or operational planning. Further, the Office of the Interconnection shall be permitted to share non-public, operational information with natural gas local distribution companies and/or intrastate natural gas pipeline operators, as appropriate, for the purpose of promoting reliable service or operational planning, provided that such party has acknowledged, in writing, that it shall not disclose, or use anyone as a conduit for disclosure of, non-public, operational information received from the Office of Interconnection to a third party or in an unduly discriminatory or preferential manner or to the detriment of any natural gas and/or electric market. Such non-public, operational information received from natural gas local distribution companies and/or intrastate natural gas pipeline operators pursuant to this section will be subject to the confidentiality provisions set forth in this section 18.17.

18.17.2 Required Disclosure.

(a) Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section 18.17.3 below, if the Office of the Interconnection is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection or its designated agents, representatives, or contractors may make disclosure of such information; provided, however, that as soon as the Office of the Interconnection learns of the disclosure requirement and prior to it or its designated agents, representatives, or contractors making disclosure, the Office of the Interconnection shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Office of the Interconnection shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Office of the Interconnection shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(b) Nothing in this section 18.17 shall prohibit or otherwise limit the Office of the Interconnection's use of information covered herein if such information was: (i) previously known to the Office of the Interconnection without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection using non-confidential information; (iii) acquired by the Office of the Interconnection from a third party which is not, to the Office of the Interconnection's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section 18.17.

(c) The Office of the Interconnection shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Agreement or of the Open Access Transmission Tariff a contractual duty of confidentiality consistent with this Agreement. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Office of the Interconnection shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

18.17.3 Disclosure to FERC and CFTC.

(a) Notwithstanding anything in this section to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC"), or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Office of the Interconnection that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection shall provide the requested information to the FERC, CFTC or their respective staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Office of the Interconnection may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Office of the Interconnection may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Office of the Interconnection shall promptly notify any affected Member(s) if the Office of the Interconnection receives from the FERC, CFTC or their staff written notice that the commission has decided to release publicly, or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission by the Office of the Interconnection.

(b) Section 18.17.3(a) above shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection shall follow the procedures in section 18.17.2 above.

(c) Pursuant to the FERC Order No. 760, as codified under 18 C.F.R. § 35.28(g)(4), to the extent that the Office of the Interconnection already collects such data described in Order No. 760, the Office of the Interconnection shall electronically deliver to the FERC, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the FERC, data related to the markets that the Office of the Interconnection administers. Section 18.17.3(a) above shall not apply to data supplied to the FERC under this subsection (c) to satisfy the FERC Order No. 760 requirements.

(d) Pursuant to the FERC Order No. 771 and any clarifying orders, as codified under 18 C.F.R. § 366.2(d), the Office of the Interconnection shall ensure that FERC is included as an addressee on all e-Tags for transactions that sink within the PJM Region.

18.17.4 Disclosure to Authorized Commissions.

(a) Notwithstanding anything in this section to the contrary, the Office of the Interconnection shall disclose confidential information, otherwise required to be maintained in confidence pursuant to this Agreement, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly-executed Certification in the form attached hereto as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the Commission within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a FERC protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the Commission, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the Commission as set forth above in this paragraph.

The Office of the Interconnection may not disclose data to an Authorized Commission during the Commission's consideration of the Certification and any filed protests. If the Commission does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section. In the event that an interested party protests the Authorized Commission's Certification and the Commission approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized

Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(ii) Any confidential information provided to an Authorized Commission pursuant to this section shall not be further disclosed by the recipient Authorized Commission except by order of the Commission.

(iii) The Office of the Interconnection shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(iv) The Authorized Commission may provide confidential information obtained from the Office of the Interconnection to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a non-disclosure agreement in the form attached hereto as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

(v) The Office of the Interconnection shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on its website, or by written request. Such schedule shall be compiled by the Office of the Interconnection, based on information provided by any Authorized Commission. The Office of the Interconnection shall update the schedule promptly upon receipt of information from an Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Office of the Interconnection in the compilation and/or maintenance of the schedule.

(b) The Office of the Interconnection may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Office of the Interconnection will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section 18.17.4(b). In any such discussions, the Office of the Interconnection shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Office of the Interconnection shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Office of the Interconnection shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

(c) As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Office of the Interconnection, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Office of the Interconnection shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section (c)(iii) below, the Office of the Interconnection shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Office of the Interconnection cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Office of the Interconnection shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Office of the Interconnection shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section (c)(ii) above, should the Office of the Interconnection or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Office of the Interconnection's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection or the Affected Member may file a complaint with the Commission pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Office of the Interconnection and/or the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Office of Interconnection shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

(d) In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Office of the Interconnection, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section.

(ii) The Office of the Interconnection shall terminate the right of such Authorized Commission to receive confidential information under this section upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Office of the Interconnection's and/or the Market Monitoring Unit's actions under this section shall be to FERC. An Authorized Commission shall be entitled to reestablish its certification as set forth in section 18.17.4(a) above by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's re-certification filing with sixty (60) days of the date of the filing, the re-certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Office of the Interconnection.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section (d)(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.5 [Reserved]

18.17.6 Disclosure of EMS and Transmission System Data to Transmission Owners on PJM EMS Terminal and Via Other Reliability or Situational Awareness Tools

(a) While the Office of the Interconnection has overall responsibility for power system reliability in the PJM Region, Transmission Owners within the PJM Region perform specified reliability functions with respect to their individual Transmission Facilities and distribution systems. In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, install a read-only terminal, or allow the Transmission Owner through a secure communication channel, in any Transmission Owner’s secure control room facility to access the Office of the Interconnection’s Energy Management System (EMS), or its other reliability or situational awareness tools, and the associated transmission and generation data under the terms and conditions set forth in this section 18.17.6.

(b) The data and information produced by the EMS or other situational awareness tool, are confidential and/or commercially sensitive because they will display the real-time status of electric transmission lines and generation facilities, the disclosure of which could impact the market and the commercial interests of its participants. In addition, the responsive information will contain detailed information about real-time grid conditions, transmission lines, power flows, and outages, which may fall within the definition of Critical Energy Infrastructure Information (CEII) as set forth in 18 CFR § 388.113. The Office of the Interconnection shall not release any generator cost, price or other market information without written authorization pursuant to section 18.17.1 (c) above unless otherwise provided for under this Agreement. The only generator information that will be made available on the read-only PJM EMS terminal is real-time MW/MVAR output and Minimum/Maximum MW Range. The transmission system information that may be made available via a reliability or situational awareness tool is limited to geospatial locations and other real-time operational data.

(c) The confidential or CEII information provided to the Transmission Owner on a read-only PJM EMS terminal or via another reliability or situational awareness tool shall only be held in the secure control room facility of the Transmission Owner. Such data shall be used for informational and operational purposes within the control room by transmission function employees as defined in the FERC's rules and regulations, 18 C.F.R. § 358. No "screen-scraping" or other data transfer of information from the read-only terminal or other situational awareness tool to other Transmission Owner systems or databases shall be permitted. No storage of information from the read-only terminal or other reliability or situational awareness tool shall be permitted. The data shall be held confidential within the transmission function environment and not be disclosed to other personnel within the Transmission Owners' company, subsidiaries, marketing organizations, energy affiliates or independent third parties. The Transmission Owner may use the confidential or CEII information only for the purpose of performing Transmission Owner's reliability function and shall not otherwise use the confidential information for its own benefit or for the benefit of any other person.

(d) In the event of any breach:

(i) The Transmission Owner(s) that caused the breach, or whose confidential information or CEII was used or disseminated beyond the limitations specified herein shall promptly notify the Office of the Interconnection, which shall, in turn, promptly notify FERC and any affected Member(s) of any inadvertent or intentional release, or possible release, of confidential or CEII information disclosed as provided above.

(ii) The Office of the Interconnection shall terminate all rights of the Transmission Owner to receive confidential or CEII information as provided in this section 18.17.6; provided, however, that the Office of the Interconnection may restore a Transmission Owners' status after consulting with the affected Member(s) whose confidential or CEII information was used or disseminated beyond the limitations specified herein and to the extent that: (a) the Office of the Interconnection determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the authorized transmission function employee; (b) there were no harm or damages suffered by the affected Member(s); or (c) similar good cause shown. Any appeal of the Office of the Interconnection's actions under this section shall be to FERC.

(iii) The Office of the Interconnection and/or the affected Member(s) shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief and/or damages with respect to any breach; and (c) the immediate return of all confidential or CEII information to the Office of the Interconnection.

(iv) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(b) and (c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.7 Disclosure of Generator Data to Transmission Owners

(a) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner upon the Transmission Owner's request the following confidential generator information for any generator that: (1) is or will be modeled within the Transmission Owner's energy management system; or (2) is or will be identified in a Transmission Owner's restoration plan:

(i) real-time unit status;

(ii) real-time megawatt output;

(iii) real-time megavolt amperes reactive ("MVAR");

(iv) the start date, start time, stop date, and stop time for the unit's scheduled outages;

(v) the unit's reactive capability curve; and

(vi) data provided for Transmission Owner use for system restoration planning purposes only, including but not limited to the unit's start-up times, ramp rate, start-up auxiliary load profile and emergency low-load operation capabilities.

(b) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner the following generator information:

(i) forecasted unit status;

(ii) forecasted megawatt output;

(iii) the start date, start time, stop date, and stop time for the information in this section 18.17.7 (b)(i) and 18.17.7 (b)(ii);

(iv) the Zone in which the generator resides; and

(v) generator operating parameters including, but not limited, to each unit's start-up times, ramp rate, Minimum Down Time, and Minimum Run Time.

(c) The Office of the Interconnection will provide the data in section 18.17.7(a) and (b) only where it possesses such data. The Office of the Interconnection shall provide this confidential information only to transmission function employees, as transmission function employee is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(d) A Transmission Owner may only use the generator data provided under section 18.17.7(a) and (b) above for the purpose of executing the Transmission Owner's reliability function and transmission function, as transmission function is defined in section 18 C.F.R. § 358 of the FERC rules and regulations, and shall not otherwise use the confidential information for its own benefit or the benefit of any other person. A Transmission Owner may disclose the generator data obtained under section 18.17.7(a) and (b) above only to the Transmission Owner's transmission function employees whose access to such data is necessary to perform the Transmission Owner's transmission functions. Transmission Owners shall not disclose the generator data obtained under section 18.17.7(a) and (b) above to any person, including marketing function employees as defined in section 18 C.F.R. § 358 of the FERC rules and regulations, except as permitted under this section 18.17.7.

(e) Each Transmission Owner shall protect and keep confidential all the information it receives from the Office of the Interconnection pursuant to this section 18.17.7. It may, copy, post, distribute, disclose or disseminate the data obtained pursuant to section 18.17.7(a) and (b) above only in the following manner. Each Transmission Owner may make a limited number of copies of written or electronic materials to enable the Transmission Owner to adequately use the information obtained pursuant to section 18.17.7(a) and (b) above within the terms and conditions of this section of this Agreement. If the Transmission Owner prints or electronically conveys any information in obtained pursuant to section 18.17.7(a) and (b) above, it shall protect each copy in accordance with this section 18.17.7 and mark each copy as "Confidential Information."

(f) The Transmission Owner shall destroy all information obtained under section 18.17.7(a) and (b) above upon the completion of the use of such information for the purpose of performing Transmission Owner's transmission functions, as transmission functions is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(g) A Transmission Owner shall be responsible for the breach of this section 18.17.7 by any of its employees or representatives. In the event of any breach by the Transmission Owner of this section 18.17.7 by any of its employees or representatives, section 18.17.6(d) shall apply to the release of the confidential information.

18.18 Termination and Withdrawal.

18.18.1 Termination.

Upon termination of this Agreement, final settlement for obligations under this Agreement shall include the accounting for the period ending with the last day of the last month for which the Agreement was effective.

18.18.2 Withdrawal.

Subject to the requirements of Operating Agreement, section 4.1(c) and Operating Agreement, Schedule 1, section 1.4.6, any Member may withdraw from this Agreement upon 90 days notice to the Office of the Interconnection.

18.18.3 Winding Up.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination or expiration of this Agreement shall survive such termination or expiration. The surviving provisions shall include, but shall not be limited to: (i) those provisions necessary to permit the orderly conclusion, or continuation pursuant to another agreement, of transactions entered into prior to the decision to terminate this Agreement, (ii) those provisions necessary to conduct final billing, collection, and accounting with respect to all matters arising hereunder, and (iii) the indemnification provisions as applicable to periods prior to such termination or expiration.

IN WITNESS whereof, the Members have caused this Agreement to be executed by their duly authorized representatives.

RESOLUTION REGARDING ELECTION OF DIRECTORS

1. Subject to the approval of the Federal Energy Regulatory Commission, the provisions of Section 7.1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (the "Operating Agreement"), to the extent that such section requires that the election of members to the PJM Board of Managers be held at the Annual Meeting of the Members, be, and they hereby are, waived, solely for election to those positions on the PJM Board of Managers that expire in the year 2001; and

2. An election of members of the PJM Board of Managers from the slate approved by the independent consultant retained by the Office of the Interconnection, is, and hereby shall be, authorized by the PJM Members Committee to occur at its meeting held on August 30, 2001; and

3. The Office of the Interconnection is, and hereby shall be, authorized to file such documents and make such pleadings before the Federal Energy Regulatory Commission as the Office of the Interconnection determines to be reasonably necessary seeking such waivers and authorizations as may be required to assure the validity of the aforementioned election of members to the PJM Board of Managers.

SCHEDULE 1
PJM INTERCHANGE ENERGY MARKET

References to section numbers in this Schedule 1 refer to sections of this Schedule 1, unless otherwise specified.

1. MARKET OPERATIONS

1.1 Introduction.

This Schedule sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the PJM Interchange Energy Market within the PJM Region. This Schedule addresses each of the three time-frames pertinent to the daily operation of the PJM Interchange Energy Market: Prescheduling, Scheduling, and Dispatch. This schedule also addresses the settlement of transactions in the single PJM Interchange Energy Market at two component settlement prices: Day-Ahead prices and Real-Time prices.

1.2 Cost-based Offers.

Unless otherwise specified in this Agreement, all cost-based offers for energy or other services to be sold on the PJM Interchange Energy Market from generating resources shall not exceed the variable cost of producing such energy or other service, as determined in accordance with Schedule 2 to this Agreement and applicable regulatory standards, requirements and determinations; provided that, a Market Seller may offer to the PJM Interchange Energy Market the right to call on energy from a resource the output of which has been sold on a bilateral basis, with the rate for such energy if called equal to the curtailment rate specified in the bilateral contract.

1.2A Transmission Losses.

1.2A.1 Description of Transmission Losses.

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines and other transmission facilities.

1.2A.2 Inclusion of Transmission Losses.

Whenever in this Schedule 1, transmission losses are included in the determination of a charge, credit, load (including deviations), or demand reduction, it is explicitly so stated and such included losses shall be those losses incurred on all Transmission Facilities (to facilitate such calculation, Transmission Owners shall ensure that all such facilities are included in the PJM network model) and those losses incurred on generator step-up transformers that a Market Seller has not elected to remove from the loss calculation. Absent such explicit statement, such losses are not included in the determination.

1.2A.3 Other Losses.

Losses incurred on facilities other than those addressed in the preceding section may be included in the determination of charges, credits, load (including real-time deviations) or demand reductions, as determined by electric distribution companies, unless this Schedule explicitly excludes such losses.

1.3 [Reserved for Future Use]

1.4 Market Participant.

1.4.1 Qualification.

(a) To become a Market Participant, an Applicant shall submit an application to the Office of the Interconnection, in such form as shall be established by the Office of the Interconnection, and such further information detailed in Tariff, Attachment Q.

(b) An Applicant that is or will be a Load Serving Entity or that will purchase on behalf of or for ultimate delivery to a Load Serving Entity shall establish to the satisfaction of the Office of the Interconnection that the end-users that will be served through energy and related services purchased in the PJM Interchange Energy Market, are located electrically within the PJM Region, or will be brought within the PJM Region prior to any purchases from the PJM Interchange Energy Market. Such Applicant shall further demonstrate that:

i) The Load Serving Entity for the end users is or will be obligated to meet the requirements of the Reliability Assurance Agreement, as applicable; and

ii) The Load Serving Entity for the end users has or will have arrangements in place for Network Transmission Service or Point-To-Point Transmission Service for all PJM Interchange Energy Market purchases.

(c) An Applicant that is a Market Buyer and is not a Load Serving Entity or purchasing on behalf of or for ultimate delivery to a Load Serving Entity shall demonstrate that:

i) The Applicant has obtained or will obtain Network Transmission Service or Point-to-Point Transmission Service for all PJM Interchange Energy Market purchases; and

ii) The Applicant's PJM Interchange Energy Market purchases will ultimately be delivered to a load in another Control Area that is recognized by NERC and that complies with NERC's standards for operating and planning reliable bulk electric systems.

(d) An Applicant shall not be required to obtain transmission service for purchases from the PJM Interchange Energy Market to cover quantity deviations from its sales in the Day-ahead Energy Market.

(e) An Applicant applying to become a Market Participant shall demonstrate that it:

i) is capable of complying with all applicable metering, data storage and transmission, and other reliability, operation, planning and accounting standards and requirements for the operation of the PJM Region and the PJM Markets, as applicable;

ii) meets the creditworthiness standards established by the Office of the

Interconnection and/or PJMSettlement, or has provided cash or a Credit Support Document acceptable to the Office of the Interconnection and/or PJMSettlement; and

iii) has paid all applicable fees and reimbursed the Office of the Interconnection and/or PJMSettlement for all unusual or extraordinary costs of processing and evaluating its application to become a Market Participant, and has agreed in its application to subject any disputes arising from its application to the PJM Dispute Resolution Procedures.

(f) The Applicant shall become a Market Participant upon a final favorable determination on its application by the Office of the Interconnection as specified below, which determination shall be made by the Office of the Interconnection in conjunction with input from PJMSettlement, and execution by the Applicant of counterparts of this Agreement.

1.4.2 Submission of Information.

The Applicant shall furnish all information reasonably requested by the Office of the Interconnection and/or PJMSettlement in order to determine the Applicant's qualification to be a Market Participant and whether the entity should be allowed to remain a Market Participant. The Office of the Interconnection and/or PJMSettlement may waive the submission of information relating to any of the foregoing criteria, to the extent the information in the Office of the Interconnection's and/or PJMSettlement's possession is sufficient to evaluate the application against such criteria.

1.4.3 Fees and Costs.

The Office of the Interconnection shall require all Applicants seeking to become a Market Participant to pay a uniform application fee, initially in the amount of $2,000, to defray the ordinary costs of processing such applications. The application fee shall be revised from time to time as the Office of the Interconnection shall determine to be necessary to recover its ordinary costs of processing applications. Any unusual or extraordinary costs incurred by the Office of the Interconnection in processing an application shall be reimbursed by the Applicant.

1.4.4 Office of the Interconnection Determination.

Upon submission of the information specified above, and such other information as shall reasonably be requested by the Office of the Interconnection and/or PJMSettlement, the Office of the Interconnection and/or PJMSettlement shall undertake an evaluation to determine whether the Applicant meets the criteria specified above, and in accordance with Tariff, Attachment Q.

As soon as practicable, but in any event not later than ninety (90) days after submission of the foregoing information, or such later date as may be necessary to satisfy the requirements of the Agreements, the Office of the Interconnection shall notify the Applicant and the Members Committee of its determination, along with a written summary of the basis for the determination, and whether there are any actions the Applicant can take that might cause the Office of the

Interconnection to change its determination, including but not limited to providing even further supplemental information, providing additional Restricted Collateral, the discontinuance of certain behaviors, implementing additional monitoring, and implementing of process or policy changes. The Office of the Interconnection and/or PJMSettlement shall respond promptly to any reasonable and timely request by an Applicant or a Member for additional information regarding the basis for the Office of the Interconnection's determination, and shall take such action as it shall deem appropriate in response to any request for reconsideration or other action submitted to the Office of the Interconnection not later than thirty (30) calendar days from the initial notification to the Members Committee. Notifications to the Members Committee shall be in compliance with Operating Agreement, section 18.17.1.

1.4.5 Existing Participants.

A Member that was previously qualified to participate as a Market Participant shall not automatically continue to be qualified to participate as a Market Participant under the Agreements. Rather, in order to retain its eligibility to continue to participate as a Market Participant in the PJM Markets, a Market Participant shall be subject to the requirements and ongoing risk evaluation in accordance with Tariff, Attachment Q.

1.4.6 Withdrawal.

(a) An Internal Market Buyer that is a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal not earlier than the effective date of (i) its withdrawal from the Reliability Assurance Agreement, or (ii) the assumption of its obligations under the Reliability Assurance Agreement by an agent that is a Market Buyer.

(b) An External Market Buyer or an Internal Market Buyer that is not a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice.

(c) Withdrawal from this Agreement shall not relieve a Market Participant of any obligation to pay for electric energy or related services purchased from the PJM Markets prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection and/or PJMSettlement prior to the date of such withdrawal, maintain and/or provide sufficient credit support until all of its transactions in the PJM Markets have been satisfied, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions or events occurring prior to such withdrawal; and provided, further, that withdrawal from this Agreement shall not relieve any Market Participant of any obligations it may have under, or constitute withdrawal from, any other Related PJM Agreement.

(d) A Market Participant that has withdrawn from this Agreement may reapply to become a Market Participant in accordance with the provisions of this section 1.4, provided it is not in default of any obligation incurred under the Agreements.

1.4.7 Limitation, Suspension, and Termination.

The Office of the Interconnection requires that Market Participants certify and provide information required and requested by the Office of the Interconnection and/or PJMSettlement at least annually as indicated in section 1.4.1, 1.4.2 and 1.4.4 above and Tariff, Attachment Q. If the Office of the Interconnection determines that the entity no longer satisfies its requirements to be a Market Participant, the Office of the Interconnection may limit and/or suspend that entity's activity in the PJM Markets until such time as it can satisfy the requirements, and if the requirements are not satisfied the Office of the Interconnection may terminate that entity's approval to be a Market Participant. As soon as practicable, the Office of the Interconnection shall notify the entity and the Members Committee of its determination, along with a written summary of the basis for the determination, and whether there are any actions the entity can take that might cause the Office of the Interconnection to change its determination, including but not limited to providing even further additional information, providing additional Restricted Collateral, the discontinuance of certain behaviors, implementing additional monitoring, and implementing of process or policy changes. The Office of the Interconnection shall respond promptly to any reasonable and timely request by a Member for additional information regarding the basis for the Office of the Interconnection's determination, and shall take such action as it shall deem appropriate in response to any request for reconsideration or other action submitted to the Office of the Interconnection not later than thirty (30) calendar days from the initial notification to the Members Committee. Notifications to the Members Committee shall be in compliance with Operating Agreement, section 18.17.1.

1.4.8. Re-entry of Defaulting Market Participant.

An Applicant who previously defaulted on any obligations owed to PJM and/or PJMSettlement that resulted in a loss to any PJM Market which was never cured, or who is not eligible for reinstatement to PJM membership pursuant to Operating Agreement, section 15.1, shall not be allowed to re-enter the PJM Markets. In addition, PJM will evaluate relevant factors to determine if an Applicant seeking to participate in the PJM Markets under a different name, affiliation, or organization should be treated as the same Market Participant that experienced a previous default that resulted in a loss to the PJM Markets under this provision. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry.

1.4A Energy Storage Resource Participation Model.

1.4A.1 Qualification.

(a) An Energy Storage Resource may opt into and out of the Energy Storage Resource Participation Model on an annual basis, in accordance with the procedures and processes defined in the PJM Manuals.

(b) Energy that an Energy Storage Resource Model Participant purchases from the PJM Interchange Energy Market must be Direct Charging Energy.

(c) An Energy Storage Resource utilizing the Energy Storage Resource Participation Model shall arrange for Network Transmission Service or Point-to-Point Transmission Service for purchases of Non-Dispatched Charging Energy. Network Transmission Service and Point-to-Point Transmission Service are not required for purchases of Dispatched Charging Energy.

(d) Energy Storage Resource Model Participants shall be eligible to be dispatched for positive and negative megawatts as otherwise applicable, to set price at positive and negative megawatt points on their offer curve as otherwise applicable, and to self-schedule positive and negative megawatt quantities, pursuant to the requirements of the PJM Manuals. Energy Storage Resources in Continuous Mode shall specify a single energy offer curve with monotonically increasing dollar values including both positive and negative megawatt quantities.

(e) Energy Storage Resource Model Participants shall be responsible for their own State of Charge Management, provided that they must comply with PJM operational orders regardless of the incidental impact on State of Charge.

(f) Energy Storage Resource Model Participants may offer quantities (including charging and discharging) equivalent to 0.1 MW or greater into all applicable PJM markets.

(g) In order to properly distinguish Direct Charging Energy from Load Serving Charging Energy, Energy Storage Resources that are distribution-connected or co-located with end-use load shall include systems that are capable of measuring the below categories of electric energy, unless a different configuration is agreed to by the electric distribution company, the Energy Storage Resource, and PJM. The categories are: i) electric energy that is withdrawn from the grid and stored in the Energy Storage Resource; ii) electric energy that is generated on-site by a resource other than the Energy Storage Resource (if any exists) and stored in the Energy Storage Resource; iii) electric energy that is discharged by the Energy Storage Resource and injected onto the grid; iv) electric energy that is discharged from the Energy Storage Resource and consumed by on-site end-use load that is not Station Power (if any such on-site end-use load exists). The measurement systems shall comply with the accuracy requirements for meters as described in the PJM Manual 01. Additional details for the configuration of such measurement systems under various specific configurations are specified in PJM Manual

14D.

If the distribution utility is unwilling or unable to net out from the host customer's retail bill Direct Charging Energy associated with an Energy Storage Resource that is distribution-connected or co-located with end-use load that is not Station Power, PJM shall not bill the Energy Storage Resource for any Direct Charging Energy.

Energy Storage Resources shall only be credited for sale transactions of electric energy in PJM markets if that same sale transaction of electric energy is not also credited at retail.

1.4B [Reserved.]

1.4C Participation of Hybrid Resources.

Hybrid Resources may participate in markets according to the following provisions in this section 1.4C, as further detailed in the PJM Manuals. Hybrid Resources are settled in markets as a single unit.

(a) Energy that the Market Participant of an Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market for charging the storage component must be Direct Charging Energy. Direct Charging Energy shall not be purchased for charging the storage component of Closed-Loop Hybrid Resources.

(b) The Market Participant of an Open-Loop Hybrid Resource shall arrange for Network Integration Transmission Service or Point-to-Point Transmission Service for purchases of Non-Dispatched Charging Energy. Network Integration Transmission Service and Point-to-Point Transmission Service are not required for purchases of Dispatched Charging Energy.

(c) Hybrid Resources consisting solely of inverter-based components shall be eligible to be dispatched for positive megawatts as otherwise applicable, to set price at positive megawatt points on their offer curve as otherwise applicable, and to self-schedule positive megawatt quantities, pursuant to the requirements of the PJM Manuals. Such Hybrid Resources shall specify a single energy offer curve with monotonically increasing dollar values. Open-Loop Hybrid Resources consisting solely of inverter-based components shall be eligible to be dispatched for negative megawatts (i.e., charging) as otherwise applicable, to set price at negative megawatt points on their offer curve as otherwise applicable, and to self-schedule negative megawatt quantities, pursuant to the requirements of the PJM Manuals. In addition, such Hybrid Resources operating in Continuous Mode shall specify a single energy offer curve with monotonically increasing dollar values including both positive and negative megawatt quantities.

(d) Hybrid Resources with a storage component shall be responsible for management of their own State of Charge, provided that they must comply with PJM operational orders regardless of the incidental impact on State of Charge.

(e) Hybrid Resources may offer quantities equivalent to 0.1 MW or greater into all applicable PJM markets.

(f) For a Hybrid Resource with a variable resource component and a storage component: during intervals in which the storage component is not actively managing the net output of such resource, the Market Participant of such resource shall indicate such status to PJM.

(g) In order to properly distinguish Direct Charging Energy from Load Serving Charging Energy, Open-Loop Hybrid Resources that are distribution-connected or co-located with end-use load shall include systems that are capable of measuring the below categories of electric energy, unless a different configuration is agreed to by the electric distribution company, the Energy Storage Resource, and PJM. The categories are: i) electric energy that is withdrawn from the grid and stored in the energy storage component; ii) electric energy that is generated on-site by a resource other than the energy storage component and stored in the energy storage component;

iii) electric energy that is discharged by the energy storage component and injected onto the grid; and iv) electric energy that is discharged from the energy storage component and consumed by on-site end-use load that is not Station Power (if any such on-site end-use load exists). The measurement systems shall comply with the accuracy requirements for meters as described in PJM Manual 01. Additional details for the configuration of such measurement systems under various specific configurations are specified in PJM Manual 14D.

If the distribution utility is unwilling or unable to net out from the host customer's retail bill Direct Charging Energy associated with an Open-Loop Hybrid Resource that is distribution-connected or co-located with end-use load that is not Station Power, then PJM shall not bill the corresponding Market Participant for any Direct Charging Energy.

Market Participants shall only be credited for sale transactions in PJM markets of electric energy produced from Open-Loop Hybrid Resources if that same sale transaction of electric energy is not also credited at retail.

1.4D Participation of Mixed Technology Facilities.

A Mixed Technology Facility with components that are physically incapable of operating independently are modeled and participate in capacity and energy markets as a single Hybrid Resource. For a Mixed Technology Facility that is eligible to participate in capacity and energy markets as either a Hybrid Resource or as multiple Co-Located Resources, the modeling classification chosen for the energy market and capacity market modeling shall match for the applicable Delivery Year.

The Co-Located Resources at a single Mixed Technology Facility participate as separate resources with separate market offers and settlements.

For a Mixed Technology Facility that has no components that participate in the capacity market, and that is eligible to participate in the energy markets as either a Hybrid Resource or as multiple Co-Located Resources, the modeling classification can be changed once per calendar year with notice to PJM by no later than May 30 for the upcoming January 1 to December 31 participation months. Once a status is chosen, it remains until another request is received. For an energy-only Mixed Technology Facility within the new resource queue process, the modeling choice must be made no later than six (6) months in advance of its initial start in the energy markets.

1.5 Market Sellers.

1.5.1 Qualification.

A Member that demonstrates to the Office of the Interconnection that the Member meets the standards for the issuance of an order mandating the provision of transmission service under section 211 of the Federal Power Act, as amended by the Energy Policy Act of 1992, may become a Market Seller upon execution of this Agreement and submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule. All Members that are Market Buyers shall become Market Sellers upon submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule.

1.5.2 Withdrawal.

(a) A Market Seller may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice; provided, however, that withdrawal shall not relieve a Market Seller of any obligation to deliver electric energy or related services to the PJM Interchange Energy Market pursuant to an offer made prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by PJMSettlement, on behalf of itself or the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such withdrawal; and provided, further, that withdrawal shall not relieve any entity that is a Market Seller and is also a Market Buyer of any obligations it may have as a Market Buyer under, or constitute withdrawal as a Market Buyer from, this Agreement or any other Related PJM Agreement.

(b) A Market Seller that has withdrawn from this Agreement may reapply to become a Market Seller at any time, provided it is not in default with respect to any obligation incurred under this Agreement.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of $500 plus 10% of each payment owed by PJMSettlement for a Load Reduction Event not to exceed $5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the $1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection's website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. The Curtailment Service Provide shall not include Critical Natural Gas Infrastructure end-use customers in the registration. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load

Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) ("Order 719-A")) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response Program, the existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.

b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.

c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.

d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant Resource Provision of Synchronized Reserve or Secondary Reserve.

(a) A Batch Load Economic Load Response Participant resource may provide Synchronized Reserve or Secondary Reserve in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Economic Load Response Participant resource" pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource.

(b) A Batch Load Economic Load Response Participant resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Secondary Reserve, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Secondary Reserve, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required).

Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Secondary Reserve to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of end-use customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Secondary Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

i. All end-use customers in an aggregation shall be specifically identified;

ii. All end-use customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all end-use customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All end-use customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one end-use customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one end-use customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An end-use customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

i. All end-use customers in an aggregation shall be specifically identified;
ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
iii. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

The Office of the Interconnection shall operate the PJM Interchange Energy Market in accordance with this Agreement.

1.6.2 Scope of Services.

The Office of the Interconnection shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including but not limited to the following:

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Operating Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

vi) Administer (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Entity principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

ix) Send a representative to meetings of the Members Committee or other Committees, subcommittees, or working groups specified in this Agreement or formed by the Members Committee when requested to do so by the chair or other head of such committee or other group;

and

x) Coordinate with adjacent Control Areas on Coordinated Transaction Scheduling (“CTS”) and forecast price calculations, in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.6.3 Records and Reports.

The Office of the Interconnection shall prepare and maintain such records and prepare such reports, including, but not limited to quarterly budget reports, as are required to document the performance of its obligations to the Market Participants hereunder in a form adopted by the Office of the Interconnection upon consideration of the advice and recommendations of the Members Committee. The Office of the Interconnection shall also produce special reports reasonably requested by the Members Committee and consistent with FERC’s standards of conduct; provided, however, the Market Participants shall reimburse the Office of the Interconnection for the costs of producing any such report. Notwithstanding the foregoing, the Office of the Interconnection shall not be required to disclose confidential or commercially sensitive information in any such report.

1.6.4 PJM Manuals.

The Office of the Interconnection shall prepare, maintain and update the PJM Manuals consistent with this Agreement. The PJM Manuals shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the LLC or any Member, and the public.

1.6A PJMSettlement

1.6A.1 Scope of Services

PJMSettlement shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including, but not limited to, the following:

(i) PJMSettlement shall be the Counterparty to transactions (including ancillary services transactions and Coordinated External Transactions) in the PJM Interchange Energy Market administered by the Office of the Interconnection;

(ii) PJMSettlement shall render bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants; and

(iii) For purposes of clarity, PJMSettlement shall not be a Counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers and Energy Storage Resources shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Economic Load Response Participant resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with

Operating Agreement, section 14, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Tariff, section 36.1.1, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement, and as may be further described in the PJM Manuals, for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by

Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Operating Agreement, Schedule 1, section 3. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to Operating Agreement, Schedule 1, section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A;Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

(iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Economic Load Response Participant resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy or if the resource is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 10-minute period.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Non-Synchronized Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Non-Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, unless the Market

Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Secondary Reserve market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Secondary Reserve to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its Markets Gateway tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new Markets Gateway reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported Markets Gateway schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable, and as may be further described in the PJM Manuals.

(b) Market Sellers selling from generation resources and/or Economic Load Response Participant resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Economic Load Response Participant resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Economic Load Response Participant resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Economic Load Response Participant resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Economic Load Response Participant resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the

Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process.

1.8.1 PJM Dispute Resolution Agreement.

Subject to the condition specified below, any Member adversely affected by a decision of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market, including the qualification of an entity to participate in that market as a buyer or seller, may seek such relief as may be appropriate under the PJM Dispute Resolution Procedures on the grounds that such decision does not have an adequate basis in fact or does not conform to the requirements of this Agreement.

1.8.2 Market or Control Area Hourly Operational Disputes.

(a) Market Participants shall comply with all determinations of the Office of the Interconnection on the selection, scheduling or dispatch of resources in the PJM Interchange Energy Market, or to meet the operational requirements of the PJM Region. Complaints arising from or relating to such determinations shall be brought to the attention of the Office of the Interconnection not later than the end of the fifth Business Day after the end of the Operating Day to which the selection or scheduling relates, or in which the scheduling or dispatch took place, and shall include, if practicable, a proposed resolution of the complaint. Upon receiving notification of the dispute, the Office of the Interconnection and the Market Participant raising the dispute shall exert their best efforts to obtain and retain all data and other information relating to the matter in dispute, and to notify other Market Participants that are likely to be affected by the proposed resolution. Subject to confidentiality or other non-disclosure requirements, representatives of the Office of the Interconnection, the Market Participant raising the dispute, and other interested Market Participants, shall meet within three Business Days of the foregoing notification, or at such other or further times as the Office of the Interconnection and the Market Participants may agree, to review the relevant facts, and to seek agreement on a resolution of the dispute.

(b) If the Office of the Interconnection determines that the matter in dispute discloses a defect in operating policies, practices or procedures subject to the discretion of the Office of the Interconnection, the Office of the Interconnection shall implement such changes as it deems appropriate and shall so notify the Members Committee. Alternatively, the Office of the Interconnection may notify the Members Committee of a proposed change and solicit the comments or other input of the Members.

(c) If either the Office of the Interconnection, the Market Participant raising the dispute, or another affected Market Participant believes that the matter in dispute has not been adequately resolved, or discloses a need for changes in standards or policies established in or pursuant to the Operating Agreement, any of the foregoing parties may make a written request for review of the matter by the Members Committee, and shall include with the request the forwarding party's recommendation and such data or information (subject to confidentiality or other non-disclosure requirements) as would enable the Members Committee to assess the matter and the recommendation. The Members Committee shall take such action on the recommendation as it shall deem appropriate.

(d) Subject to the right of a Market Participant to obtain correction of accounting or billing errors, the LLC or a Market Participant shall not be entitled to actual, compensatory, consequential or punitive damages, opportunity costs, or other form of reimbursement from the LLC or any other Market Participant for any loss, liability or claim, including any claim for lost profits, incurred as a result of a mistake, error or other fault by the Office of the Interconnection in the selection, scheduling or dispatch of resources.

1.9 Prescheduling.

The following procedures and principles shall govern the prescheduling activities necessary to plan for the reliable operation of the PJM Region and for the efficient operation of the PJM Interchange Energy Market.

1.9.1 Outage Scheduling.

The Office of the Interconnection shall be responsible for coordinating and approving requests for outages of generation and transmission facilities as necessary for the reliable operation of the PJM Region, in accordance with the PJM Manuals. The Office of the Interconnection shall maintain records of outages and outage requests of these facilities.

1.9.2 Planned Outages.

(a) A Generator Planned Outage shall be included in Generator Planned Outage schedules established prior to the scheduled start date for the outage, in accordance with standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall conduct Generator Planned Outage scheduling for Generation Capacity Resources in accordance with the Reliability Assurance Agreement and the PJM Manuals and in consultation with the Market Sellers owning or controlling the output of such resources. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from all or part of a generation resource undergoing an approved Generator Planned Outage. If the Office of the Interconnection determines that approval of a Generator Planned Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval or withdraw a prior approval. Approval of a Generator Planned Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. The Market Seller shall provide the Office of the Interconnection with an estimate of the amount of time it needs to return to service any Generation Capacity Resource on Generator Planned Outage that is already underway. If the Office of the Interconnection withholds or withdraws its approval of a Generator Planned Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Planned Outage at the earliest practical time. The Office of the Interconnection shall if possible propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Planned Outage.

(c) The Office of the Interconnection shall conduct Transmission Planned Outage scheduling in accordance with procedures specified in the Consolidated Transmission Owners Agreement and the PJM Manuals, and in accordance with the following procedures:

(i) Transmission Owners shall use reasonable efforts to submit Transmission Planned Outage schedules one year in advance but by no later than the first of the month six months in advance of the requested start date for all outages that are expected to exceed five working days duration, with regular (at least monthly) updates as new information becomes available.

(ii) If notice of a Transmission Planned Outage is not provided in accordance with the requirements in subsection (i) above, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

(iii) Transmission Owners shall submit notice of all Transmission Planned Outages to the Office of the Interconnection by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.

(iv) If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection shall perform this analysis and notify the Transmission Owner in a timely manner if it will require rescheduling of the outage. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the

Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

(v) The Office of the Interconnection reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure reliable system operations on a case by case basis regardless of duration or date of submission.

(vi) The Office of the Interconnection shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the Transmission Owner; provided, however, that the Office of the Interconnection shall not post on OASIS notice of any component of a Transmission Planned Outage to the extent such component shall directly reveal a generator outage. In such cases, the Transmission Owner, in addition to providing notice to the Office of the Interconnection as required above, concurrently shall inform the affected Generation Owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the Generation Owner on matters of safety to persons, facilities, and equipment. The Transmission Owner shall not notify any other Market Participant of such outage and shall arrange any other necessary coordination through the Office of the Interconnection.

In addition, if the Office of the Interconnection determines that transmission maintenance schedules proposed by one or more Members would significantly affect the efficient and reliable operation of the PJM Region, the Office of the Interconnection may establish alternative schedules, but such alternative shall minimize the economic impact on the Member or Members whose maintenance schedules the Office of the Interconnection proposes to modify.

(d) The Office of the Interconnection shall coordinate resolution of outage or other planning conflicts that may give rise to unreliable system conditions. The Members shall comply with all maintenance schedules established by the Office of the Interconnection.

1.9.3 Generator Maintenance Outages.

(a) A Generator Maintenance Outage may only be scheduled if approved by the Office of the Interconnection prior to the requested start date for the outage, in accordance with subsection (b) hereof and the standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall schedule Generator Maintenance Outages for Generation Capacity Resources in accordance with the procedures specified in the PJM Manuals and in consultation with the Market Seller owning or controlling the output of such resources. The Office of the Interconnection shall approve requests for Generator Maintenance Outages for such a Generation Capacity Resource unless the outage would threaten the adequacy of reserves in, or the reliability of, the PJM Region. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from a generation resource undergoing an approved full or partial Generator Maintenance Outage. If the Office of the Interconnection determines that approval of a Generator Maintenance Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval, withdraw a prior approval, or rescind a prior approval of a Generator Maintenance Outage that is already underway. Approval of a Generator Maintenance Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. In addition, if the Office of the Interconnection determines that it must rescind its approval of a Generator Maintenance Outage that is already underway in order to preserve the reliable operation of the PJM Region, the Office of the Interconnection will provide the Market Seller of the Generation Capacity Resource at least 72 hours' notice thereof. The Market Seller shall be required to make the Generation Capacity Resource available for normal operation within 72 hours of such notice. If the generator is not made available for normal operation by 72 hours after the notice of the rescission of the approval of the Generator Maintenance Outage, for the remaining time the resource continues on the outage it shall be deemed to have experienced a Generator Forced Outage. If the Office of the Interconnection withholds, withdraws or rescinds approval of a Generator Maintenance Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Maintenance Outage at the earliest practical time. The Office of the Interconnection shall, if possible, propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Maintenance Outage.

1.9.4 Forced Outages.

(a) Each Market Seller that owns or controls a pool-scheduled resource, or Generation Capacity Resource whether or not pool-scheduled, shall: (i) advise the Office of the Interconnection of a Generator Forced Outage suffered or anticipated to be suffered by any such resource as promptly as possible; (ii) provide the Office of the Interconnection with the expected date and time that the resource will be made available; and (iii) make a record of the events and circumstances giving rise to the Generator Forced Outage. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or satisfy delivery obligations, from a generation resource undergoing a Generator Forced Outage. A Generation Capacity Resource committed to PJM loads through an RPM Auction, FRR Capacity Plan, or by designation as a replacement resource under Attachment DD of the PJM Tariff, that does not deliver all or part of its scheduled energy shall be deemed to have experienced a Generator Forced Outage with respect to such undelivered energy, in accordance with standards and procedures for full and partial Generator Forced Outages specified in the Reliability Assurance Agreement, and the PJM Manuals.

(b) The Office of the Interconnection shall receive notification of Forced Transmission Outages, and information on the return to service, of Transmission Facilities in the PJM Region in accordance with standards and procedures specified in, as applicable, the Consolidated Transmission Owners Agreement and the PJM Manuals.

1.9.4A Transmission Outage Acceleration.

(a) Planned Transmission Outages and Forced Transmission Outages otherwise scheduled pursuant to sections 1.9.2 and 1.9.4 respectively of this Schedule may be accelerated or rescheduled at the request of a Generation Owner or other Market Participant in accordance with the terms and conditions of this section 1.9.4A and the PJM Manuals.

(b) Transmission Outages Requiring Coordination With A Specific Generation Owner.

(i) Receipt of Acceleration Request. Prior to a scheduled Planned Transmission Outage associated with the interconnection of a generating unit to the Transmission System, the affected Generation Owner may request that the outage be accelerated or rescheduled. Such Acceleration Request shall be submitted to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals.

(ii) Determination to Accommodate Acceleration Request. Upon receipt of an Acceleration Request, the Office of the Interconnection shall notify the affected Transmission Owner of such Acceleration Request. The affected Transmission Owner shall determine, in its sole discretion, whether to accelerate or reschedule a transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards, and shall consider any requirements contained in pertinent collective bargaining agreements. In the event that the affected Transmission Owner determines to accelerate or reschedule a transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an estimate of the cost to accelerate or reschedule the transmission outage and the revised schedule for the transmission outage (“Acceleration Estimate”).

(iii) Provision of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that the Generation Owner has met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Generation Owner with the Acceleration Estimate. In the event that the Generation Owner does not meet the creditworthiness standard, the Office of the Interconnection shall not provide the Acceleration Estimate and the transmission outage shall not be accelerated or rescheduled. Upon receipt of the Acceleration Estimate, the Generation Owner, within the time period specified in the PJM Manuals, shall notify the Office of the

Interconnection as to whether it desires to accelerate or reschedule the transmission outage pursuant to the terms of the Acceleration Estimate.

(iv) Cost Responsibility. In the event the Generation Owner notifies the Office of the Interconnection that it desires to proceed with the acceleration or rescheduling of the transmission outage pursuant to section 1.9.4A(a)(iii), the Generation Owner shall be solely responsible for actual costs incurred by the affected Transmission Owner for the acceleration or rescheduling of the transmission outage. The Generation Owner's cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete the outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the Generation Owner. After receipt of such notification, within the time period set forth in the PJM Manuals, the Generation Owner shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection shall notify the affected Transmission Owner of the Generation Owner's decision. In the event the Generation Owner desires not to proceed, the transmission outage shall occur according to normal work practices and the Generation Owner shall be responsible for all incurred costs and committed costs and obligations of the affected Transmission Owner for the acceleration or rescheduling of the transmission outage as of the date that the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(c) Transmission Outages That Could Cause Congestion Revenue Inadequacy.

(i) Posting of Transmission Outage. In the event that the Office of the Interconnection determines that a Planned Transmission Outage or Forced Transmission Outage could exceed five days and could cause congestion revenue inadequacy in excess of $500,000, the Office of the Interconnection shall post a notice of such transmission outage on its internet site. Within the time period and pursuant to the procedures set forth in the PJM Manuals, any Market Participant may request that such transmission outage be accelerated or rescheduled.

(ii) Determination to Accelerate or Reschedule Transmission Outage. Upon receipt of the Acceleration Request(s) pursuant to section 1.9.4A(b)(i), the Office of the Interconnection shall notify the affected Transmission Owner of such request(s). The affected Transmission Owner shall determine in its sole discretion whether to accelerate or reschedule the transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards and shall consider any requirements contained in pertinent collective bargaining agreements. If the affected Transmission Owner determines to accelerate or reschedule the transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an Acceleration Estimate. In the event that Market Participants submit requests which would require different schedules for a transmission outage, the Office of the Interconnection, in consultation with the affected Transmission Owner, shall determine the most effective option, which will be included in the Acceleration Estimate.

(iii) Notification of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that Market Participants requesting acceleration or rescheduling of transmission outages have met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Market Participants with the Acceleration Estimate and the number of Market Participants requesting acceleration or rescheduling of the transmission outage that meet the creditworthiness standards. After receipt of the Acceleration Request, within the time period set forth in the PJM Manuals, each requesting Market Participant meeting the creditworthiness standards shall notify the Office of the Interconnection whether it desires to accelerate or reschedule the transmission outage as set forth in the Acceleration Estimate, and if it desires to accelerate or reschedule the transmission outage, the amount it is willing to pay for such acceleration or rescheduling.

(iv) Evaluation of Acceleration Requests. Upon receipt of Market Participant(s) notifications pursuant to subsection 1.9.4A(b)(iii), the Office of the Interconnection shall determine, based on the amount Market Participants collectively are willing to pay for accelerating or rescheduling of the transmission outage, whether the transmission outage should be accelerated or rescheduled. The transmission outage shall be accelerated or rescheduled if the amount that the Market Participants collectively are willing to pay for accelerating or rescheduling a transmission outage exceeds the Acceleration Estimate by the following margins: (a) for outages to equipment outside a substation, two times the Acceleration Estimate; and (b) for outages to equipment inside a substation, five times the Acceleration Estimate. These margins are designed to provide a reasonable degree of certainty that the actual costs of accelerating or rescheduling the transmission outage will not exceed the amount the Market Participants are willing to pay. In all events, transmission outages will be accelerated or rescheduled pursuant to requests made under section 1.9.4A(c) only when the requested acceleration or rescheduling would reduce the amount of congestion revenue inadequacy resulting from the outage as determined by the Office of the Interconnection.

(v) Cost Responsibility. Each Market Participant which notifies the Office of the Interconnection pursuant to section 1.9.4A(b)(iii) that it is willing to pay for the acceleration or rescheduling of a transmission outage shall be responsible for the actual costs of such acceleration or rescheduling on a pro-rata basis based on the amount it specified it was willing to pay for the acceleration or rescheduling. Market Participants' cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete a transmission outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the affected Market Participants of such increase. Within the time period set forth in the PJM Manuals, each affected Market Participant shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection then shall notify the affected Transmission Owner of each affected Market Participant's decision. In the event that, because one or more Market Participants determine not to proceed, there would be insufficient funds to pay for the full cost of accelerating or rescheduling a transmission outage, the transmission outage shall not continue to be accelerated or rescheduled and shall occur according to normal work practices. In such instance, the Market Participants shall be responsible on a pro-rata basis for all incurred costs and committed costs and obligations of the affected Transmission Owner as of the date the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(d) Posting Revised Transmission Outages. The Office of the Interconnection shall post on its internet site all revised transmission outage schedules resulting from implementation of this section 1.9.4A, pursuant to the procedures in the PJM Manuals, and simultaneously shall notify affected Market Participants or Generation Owners that submitted Acceleration Requests of the Transmission Owner's agreement to accelerate or reschedule the outage.

1.9.5 Market Participant Responsibilities.

Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered.

1.9.6 Internal Market Buyer Responsibilities.

Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based Start-up Costs and No-load Costs may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit both Start-up Costs and No-load Costs on either a market basis or a cost basis and any such election shall be submitted on or before March 31 for the period of April 1 through September 30, and on or before September 30 for the period October 1 through March 31. The election of market-based or cost-based Start-up Costs and No-load Costs shall remain in effect without change throughout the applicable periods.

(i) If a Market Seller chooses to submit market-based Start-up Costs and No-load Costs, such Market Seller, in its Offer Data, shall submit the level of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends to request such fees. The Office of the Interconnection shall reject any request for Start-up Costs and No-load Costs in a Market Seller's Offer Data that does not conform to the Market Seller's specification on file with the Office of the Interconnection.

(ii) If a Market Seller chooses to submit cost-based Start-up Costs and No-load Costs, such fees must be calculated as specified in the PJM Manuals and the Market Seller may change both cost-based fees hourly and must change both fees as the associated costs change, but no more frequently than daily.

1.9.8 Transmission Owner Responsibilities.

All Transmission Owners shall regularly update and verify facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals:

(a) Each Transmission Owner shall verify to the Operations Planning Department (or successor Department) of the Office of the Interconnection all of its transmission facility ratings two months prior to the beginning of the summer season (i.e., on April 1) and two months prior to the beginning of the winter season (i.e., on October 1) each calendar year, and shall provide detailed data justifying such transmission facility ratings when directed by the Office of the Interconnection.

(b) In addition to the seasonal verification of all ratings, each Transmission Owner shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection updates to its transmission facility ratings as soon as such Transmission Owner is aware of any changes. Such Transmission Owner shall provide the Office of the Interconnection with detailed data justifying all such transmission facility ratings changes.

(c) All Transmission Owners shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection formal documentation of any procedure for changing facility ratings under specific conditions, including: the detailed conditions under which such procedures will apply, detailed explanations of such procedures, and detailed calculations justifying such pre-established changes to facility ratings. Such procedures must be updated twice each year consistent with the provisions of this Section.

1.9.9 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall perform seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system, in accordance with the procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall maintain and update tables setting forth Operating Reserve and other reserve objectives as specified in the PJM Manuals and as consistent with the Reliability Assurance Agreement.

(c) The Office of the Interconnection shall receive and process requests for firm and non-firm transmission service in accordance with procedures specified in the PJM Tariff.

(d) The Office of the Interconnection shall maintain such data and information relating to generation and transmission facilities in the PJM Region as may be necessary or appropriate to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM Region.

(e) The Office of the Interconnection shall maintain an historical database of all transmission facility ratings, and shall review, and may modify or reject, any submitted change or any submitted procedure for pre-established transmission facility rating changes. Any dispute between a Transmission Owner and the Office of the Interconnection concerning transmission facility ratings shall be resolved in accordance with the dispute resolution procedures in schedule 5 to the Operating Agreement; provided, however, that the rating level determined by the Office of the Interconnection shall govern and be effective during the pendency of any such dispute.

(f) The Office of the Interconnection shall coordinate with other interconnected Control Area as necessary to manage, alleviate or end an Emergency.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs;

(3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller’s cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller’s cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, \$1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and

cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second December 31 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller

has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with

section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator

Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time

Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and

No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer

Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Operating Agreement, Schedule 1, section 1.10 and Operating Agreement, Schedule 1, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In performing the security constrained economic dispatch of the system, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program. The State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on transmission facilities as defined in the PJM Manuals.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled or self-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled or self-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection upon receipt.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Economic Load Response Participant resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Economic Load Response Participant resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Economic Load Response Participant resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from available either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the Synchronized Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.001. PJMSettlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from pool-scheduled generation resources as needed to ensure the Primary Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost between providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.

(c) The Office of the Interconnection shall dispatch generation resources for Non-

Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM

Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

1.11.6 Real-time Energy Market Suspension.

If the Office of the Interconnection declares a Market Suspension (the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour), Real-time Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.5.2 and the Office of the Interconnection shall notify Market Participants of the Market Suspension as soon as practicable.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Operating Reserve Credit shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Operating Reserve Credit shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

(c) The Transmission Provider may implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.

(d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.

(e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

1.13 Coordinated Transaction Scheduling

(a) The provisions of this Section 1.13 apply to Coordinated External Transactions.

(b) A CTS Interface Bid submitted in the Real-time Energy Market shall specify the sink, the corresponding source, and a duration consisting of one or more consecutive quarter-hour increments. A CTS Interface Bid shall include a bid price and a bid quantity for each quarter-hour increment. A CTS Interface Bid may not be submitted or modified later than 75 minutes before the start of the hour that includes the first quarter-hour increment for which the CTS Interface Bid is offered. A CTS Interface Bid must include the associated NERC E-Tag at the time it is submitted.

(c) CTS Interface Bids are cleared in economic merit order for each quarter-hour increment, based upon the forecasted price differential across the CTS Enabled Interface. Subject to Transmission System conditions and operating limits as described in this subsection (c) below, and credit limits and requirements as described in Attachment Q of the PJM Tariff, a CTS Interface Bid will clear if the forecasted price differential across the CTS Enabled Interface is greater than or equal to the bid price. The total quantity of CTS Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the CTS Interface Bids of all Market Participants, Transmission System conditions, and any real-time operating limits necessary to ensure reliable operation of the Transmission System.

(d) Any Coordinated External Transaction, or portion thereof, submitted to the Real-time Energy Market will not be scheduled if PJM expects that the transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

2. CALCULATION OF LOCATIONAL MARGINAL PRICES

2.1 Introduction.

The Office of the Interconnection shall calculate the price of energy at the load buses and generation buses in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region on the basis of Locational Marginal Prices. Locational Marginal Prices determined in accordance with this Section shall be calculated on a day-ahead basis for each hour of the Day-ahead Energy Market, and every five minutes during the Operating Day for the Real-time Energy Market.

2.2 General.

The Office of the Interconnection calculates Locational Marginal Prices separately from and subsequent to the security-constrained unit commitment and security-constrained economic dispatch of the system, the latter of which is referred to as the dispatch run. The calculation of Locational Marginal Prices, which occurs in a process referred to as the pricing run, is based on the same optimization problem as the security-constrained economic dispatch. The objective of both the dispatch run and the pricing run is to serve load and meet reserve requirements at the least cost while respecting transmission constraints. However, Integer Relaxation is applied only to Eligible Fast-Start Resources committed in the pricing run to provide energy.

In the dispatch run a commitment state of 1 represents a resource is committed and 0 represents a resource is not committed. In the pricing run Integer Relaxation allows the commitment state of a committed Eligible Fast-Start Resource to be lowered to any value between 0 and 1, inclusive of 0 and 1. This in turn allows the optimization problem in the pricing run to use any fraction of a committed Eligible Fast-Start Resource's output, including an amount less than the resource's offered Economic Minimum output, in the determination of Locational Marginal Prices.

The process for the determination of Locational Marginal Prices in the Day-ahead Energy Market is described in Operating Agreement, Schedule 1, section 2.6 and the process for the determination of Locational Marginal Prices in the Real-time Energy Market is described in Operating Agreement, Schedule 1, section 2.5.

2.2A Fast-Start Resources.

(a) A Fast-Start Resource is a resource capable of operating with a notification time plus startup time of one hour or less and a Minimum Run Time of one hour or less or Minimum Down Time of one hour or less based on its operating characteristics. Fast-Start Resources include Economic Load Response Participant resources and the following types of generation resources: fuel cell, combustion turbine, diesel, hydropower, battery, solar, landfill, and wind. Other resources may be considered a Fast-Start Resource by obtaining written approval from the Office of the Interconnection pursuant to subsection (b) below.

(b) The Market Seller of a resource not considered a Fast-Start Resource may obtain approval for such resource to be considered a Fast-Start Resource by submitting to the Office of the Interconnection and the Market Monitoring Unit a written request for approval and provide documentation to support the resource's capability of operating with a notification time plus startup time of one hour or less and a Minimum Run Time of one hour or less or Minimum Down Time of one hour or less based on its operating characteristics, such as historical operating data showing the ability to provide energy upon an hour's notice. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval for a resource to be a Fast-Start Resource. A Market Seller must submit such a request, and supporting documentation, no later than April 15, and the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be considered Fast-Start capable and provide no later than the following May 30 written notification to the Market Seller of such determination. If the request is granted, the resource shall be considered a Fast-Start Resource as of the next June 1 following submission of the request. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(c) To the extent a Fast-Start Resource fails, on a persistent basis, to provide energy or load reduction consistent with offer parameters on which it was committed of a notification time plus startup time of one hour or less and a Minimum Run Time of one hour or less or minimum down time of one hour or less, the Office of the Interconnection may deem, in consultation with the Market Monitoring Unit, that a resource is no longer considered a Fast-Start Resource. The Office of the Interconnection shall provide written notification, with a written explanation, to the Market Seller of such determination. A resource may regain Fast-Start Resource status pursuant to subsection (b) above.

(d) A Fast-Start Resource shall be an Eligible Fast-Start Resource when the following apply:

(i) A generation resource is committed on an offer with a notification time plus startup time of one hour or less and a Minimum Run Time of one hour or less.

(ii) An Economic Load Response Participant resource is committed on an offer with a notification time of one hour or less and a Minimum Down Time of one hour or less.

(iii) The resource shall not be any of the following:

a. Self-scheduled for Energy in a given interval;
b. A pumped storage hydropower unit scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market;
c. A pseudo-tied resource that does not provide all of their output to PJM; or
d. A dynamically scheduled resource.

Only Eligible Fast-Start Resources shall have Integer Relaxation applied in the calculation of Locational Marginal Prices.

2.3 Reserved for Future Use.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this section shall be determined every five minutes.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine the applicable marginal energy offer based on the latest approved real-time security constrained economic dispatch solution available for the target time for the resources being dispatched by the Office of the Interconnection using the offer schedule on which the resource is committed in the dispatch run.

The Office of the Interconnection will determine a resource's applicable marginal energy offer, as described in the PJM Manuals, based on the latest approved real-time security constrained economic dispatch solution available for the target time and the Market Seller's Incremental Energy Offer curve or, for Eligible Fast-Start Resources, the Market Seller's Composite Energy Offer in which the resource is evaluated in the Pricing Run. For Eligible Fast-Start Resources, the amortized Start-Up Costs and amortized No-load Costs, expressed in dollars per megawatt-hour, are added to the resource's Incremental Energy Offer to determine a Composite Energy Offer, as described below:

(i) The amortized Start-Up Cost for a generation resource shall equal the resource's applicable Start-Up Cost, as determined in accordance with the PJM Manuals, amortized over (A) the resource's Economic Maximum or Emergency Maximum output, whichever is applicable, and (B) the resource's Minimum Run Time, rounded up to the nearest twelfth of an hour. The amortized Start-Up Cost is included in the resource's Composite Energy Offer in each five-minute interval in which the resource is pool-scheduled during the resource's Minimum Run Time. If the Minimum Run Time is less than 5 minutes, the Minimum Run Time used to calculate the amortized Start-Up Cost is 5 minutes and the amortized Start-Up Cost is added to the Incremental Energy Offer for the first five minute interval in which the resource runs. After the Minimum Run Time has been met, the amortized Start-Up Cost is not included in the Composite Energy Offer. To determine the amortized Start-Up Cost for Economic Load Response Participant resources, the Minimum Down Time is used in place of Minimum Run Time and shutdown cost is used in place of Start-Up Cost in the above equation.

The amortized Start-Up Cost, to the extent it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, shall be *adjusted* if the resource's applicable Start-Up Cost exceeds the reasonably expected cost*, as described in subsection (iii) below*.

(ii) The amortized No-load Cost shall equal the resource's applicable No-load Cost, amortized over the resource's Economic Maximum or Emergency Maximum output, whichever is applicable, and included in the Composite Energy Offer for each interval in which the resource is pool-scheduled.

The amortized No-load Cost, to the extent it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, shall be *adjusted* if the resource's applicable Incremental Energy Offer and No-load Cost exceed the reasonably expected cost*, as described in subsection (iii) below*.

(iii) To the extent a Composite Energy Offer of a generation resource that is an Eligible Fast-Start Resource is less than $2,000/megawatt-hour and is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted Start-Up Cost and No-load Cost against the resource's reasonably expected Start-Up Cost and No-load Cost, adjustments may be applied to yield a Composite Energy Offer no lower than $1,000/megawatt-hour at the Economic Maximum output as follows:

1) If the submitted Start-Up Cost and No-load Cost do not exceed the respective reasonably expected costs, no adjustments shall be made to the submitted Composite Energy Offer.

2) If the submitted Start-Up Cost does not exceed the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does exceed the reasonably expected No-load Cost, then the Composite Energy offer shall equal the Incremental Energy Offer plus the amortized submitted Start-Up Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value less than $1,000/megawatt-hour, then the Composite Energy Offer shall include an amortized No-load Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

3) If the submitted Start-Up Cost exceeds the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does not exceed the reasonably expected No-load Cost, then the Composite Energy Offer shall equal the Incremental Energy Offer plus the amortized No-load Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value less than $1,000/megawatt-hour, then the Composite Energy Offer shall include an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

4) If both the submitted Start-Up Cost and No-load Cost exceed the respective reasonably expected costs and the Incremental Energy Offer is below $1,000 MWh, then the Composite Energy Offer shall equal $1,000/megawatt-hour and be composed of the resource's: (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $1,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is *less than $1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.*

(c) *If a generation resource that is* an Eligible Fast-Start Resource submits a market-based offer that results in a Composite Energy Offer that exceeds $1,000/megawatt-hour *at the resource's Economic Maximum*:

(i) If the Incremental Energy Offer of the market-based schedule exceeds the Incremental Energy Offer of the associated cost-based offer*, then the amortized Start-Up Cost and the amortized No-load Cost for the market-based schedule shall both be considered to exceed their respective reasonably expected cost, and the Composite Energy Offer shall be equal to $1,000/megawatt-hour and be composed of the resource's (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $1,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is less than $1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum*.

(ii) *If the Incremental Energy Offer of the market-based schedule is not greater than the Incremental Energy Offer of the associated cost-based offer and:*

(*1*) *If* the amortized No-load Cost for the market-based schedule *exceeds* the No-load Cost of the associated cost-based offer *or*, exceeds the reasonably expected cost *of such cost-based offer, then the amortized No-load Cost shall be adjusted in the matter set forth in subsections (b)(iii)(2) and (4) above, as applicable.*

(2) If the amortized Start-Up Cost for the market-based schedule exceeds the Start-Up Cost of the specified on the associated cost-based offer or exceeds the reasonably expected cost of the Start-Up Cost of such cost-based offer, then the amortized Start-Up Cost shall be adjusted in the manner set forth in subsections (b)(iii)(3) and (4), as applicable.

(3) To the extent the Composite Energy Offer resulting from subsections (c)(ii)(1) and (2) above would exceed $2,000/MWh, then the Composite Energy Offer shall equal $2,000/megawatt-hour and the submitted Start-Up Cost and No-load Cost shall be adjusted in the manner set forth in subsection (e) below.

(d) For purposes of calculating Real-time Prices, the applicable marginal Incremental Energy Offer used in the calculation of Real-time Prices shall not exceed $2,000/megawatt-hour.

(e) *If a generation* resource that is an Eligible Fast-Start Resource submits an offer that results in a Composite Energy Offer with a maximum segment that exceeds $2,000/megawatt-hour *and such offer is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted Start-Up Cost and No-load Cost against the resource's reasonably expected Start-Up Cost and No-load Cost, the following adjustments will be made to cap the offer at no higher than $2,000/megawatt-hour:*

(i) If the submitted Start-Up Cost and No-load Cost do not exceed the respective reasonably expected costs, the Composite Energy Offer shall equal $2,000/megawatt-hour and be composed of: (i) the resource's Incremental Energy Offer, (ii) to the extent the Incremental Energy Offer is less than $2,000/megawatt-hour, a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $2,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is less than $2,000/megawatt-hour, a Start-Up Cost value an amortized Start-Up Cost value sufficient to make the Composite Energy Offer at Economic Maximum equal to $2,000/megawatt-hour.

(ii) If the submitted Start-Up Cost does not exceed the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does exceed the reasonably expected No-load Cost, then the Composite Energy offer shall equal the Incremental Energy Offer plus the amortized submitted Start-Up Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value greater than $2,000/megawatt-hour, then the Composite Energy Offer shall include an amortized Start Up Cost value sufficient to make the Composite Energy Offer equal to $2,000/megawatt-hour.

(iii) If the submitted Start-Up Cost exceeds the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does not exceed the reasonably expected No-load Cost, then the Composite Energy Offer shall equal the Incremental Energy Offer plus the amortized No-load Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value greater than $2,000/megawatt-hour, then the Composite Energy Offer shall include an amortized No-load Cost value sufficient to make the Composite Energy Offer equal to $2,000/megawatt-hour.

(iv) If the submitted Start-Up Cost and No-load Cost both exceed the respective reasonably expected costs, the Composite Energy Offer shall equal the lesser of the resource's Incremental Energy Offer or $2,000/megawatt-hour.

(v) To the extent any of the foregoing subsections (e)(ii) through (e)(iv) would result in a Composite Energy Offer less than $1,000/MWh at Economic Maximum, the Composite Energy Offer shall equal $1,000/megawatt-hour and be composed of the resource's: (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic

Maximum, and (iii) to the extent the sum of the foregoing is less than \$1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to \$1,000/megawatt-hour at Economic Maximum.

(f) To the extent an Economic Load Response Participant resource's Composite Energy Offer is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted shutdown cost against the resource's reasonably expected shutdown costs, adjustments may be applied to yield a Composite Energy Offer, at Economic Maximum, no lower than \$1,000/megawatt-hour and no greater than \$2,000/megawatt-hour as follows:

(i) If a Composite Energy Offer at Economic Maximum is greater than \$1,000/megawatt-hour but does not exceed \$2,000/megawatt-hour, and the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, does not exceed the resource's reasonably expected shutdown cost, then no adjustments shall be made to the submitted Composite Energy Offer.

(ii) If the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, exceeds the resource's reasonably expected shutdown cost, then the Composite Energy Offer shall equal: (i) the resource's Incremental Energy Offer, and (ii) to the extent the Incremental Energy Offer is less than \$1,000/megawatt-hour, a shutdown value equal to the lesser of the resource's amortized submitted shutdown cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to \$1,000/megawatt-hour.

(iii) If the Composite Energy Offer at Economic Maximum exceeds \$2,000/megawatt-hour and the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, does not exceed the resource's reasonably expected shutdown cost, then the Composite Energy Offer shall equal \$2,000/megawatt-hour: (i) the resource's Incremental Energy Offer, and (ii) to the extent the Incremental Energy Offer is less than \$2,000/megawatt-hour, a shutdown value sufficient to make the Composite Energy Offer equal to \$2,000/megawatt-hour.

(g) Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.4A Determination of Energy Offers Used in Calculating Day-ahead Prices.

(a) Day-ahead Prices derived in accordance with this section shall be determined for every hour.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used to calculate the Day-ahead Prices, the Office of the Interconnection shall determine the applicable marginal energy offer of the resources being dispatched by the Office of the Interconnection using the offer schedule on which the resource is committed in the dispatch run.

The Office of the Interconnection will determine a resource's applicable marginal energy offer by comparing the megawatt output of the resource from the pricing run with the Market Seller's Incremental Energy Offer curve or, for Eligible Fast-Start Resources, the Market Seller's Composite Energy Offer. For Eligible Fast-Start Resources, the amortized Start-Up Costs and amortized No-load Costs, expressed in dollars per megawatt-hour, are added to the resource's Incremental Energy Offer to determine a Composite Energy Offer, as described below:

(i) The amortized Start-Up Cost for a generation resource shall equal the resource's applicable Start-Up Cost, as determined in accordance with the PJM Manuals, amortized over (A) the resource's Economic Maximum or Emergency Maximum output, whichever is applicable and (B) the resource's Minimum Run Time. For the purposes of this calculation, the Minimum Run Time is set to one hour. The amortized Start-Up Cost is included the resource's Composite Energy Offer during the resource's Minimum Run Time. After the Minimum Run Time has been met the amortized Start-Up Cost is not included in the Composite Energy Offer. To determine the amortized Start-Up Cost for Economic Load Response Participant resources, the Minimum Down Time is used in place of Minimum Run Time and shutdown cost is used in place of Start-Up Cost in the above equation.

The amortized Start-Up Cost, to the extent it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, shall be adjusted if the resource's applicable Start-Up Cost exceeds the reasonably expected cost, as described in subsection (iii) below.

(ii) The amortized No-load Cost shall equal the resource's applicable No-load Cost, amortized over the resource's Economic Maximum or Emergency Maximum output, whichever is applicable output and included in the Composite Energy Offer for all intervals in which the resource is pool-scheduled.

The amortized No-load Cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, shall be adjusted if the resource's applicable Incremental Energy Offer and No-load Cost exceed the reasonably expected cost, as described in subsection (iii) below.

(iii) To the extent a Composite Energy Offer of a generation resource that is an Eligible Fast-Start Resource is less than $2,000/megawatt-hour and is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted Start-Up Cost and No-load Cost against the resource's reasonably expected Start-Up Cost and No-load Cost, adjustments may be applied to yield a Composite Energy Offer no lower than $1,000/megawatt-hour at Economic Maximum as follows:

1) If the submitted Start-Up Cost and No-load Cost do not exceed the respective reasonably expected costs, no adjustments shall be made to the submitted Composite Energy Offer.

2) If the submitted Start-Up Cost does not exceed the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does exceed the reasonably expected No-load Cost, then the Composite Energy offer shall equal the Incremental Energy Offer plus the amortized submitted Start-Up Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value less than $1,000/megawatt-hour, then the Composite Energy Offer shall include an amortized No-load Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

3) If the submitted Start-Up Cost exceeds the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does not exceed the reasonably expected No-load Cost, then the Composite Energy Offer shall equal the Incremental Energy Offer plus the amortized No-load Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value less than $1,000/megawatt-hour, then the Composite Energy Offer shall include an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

4) If both the submitted Start-Up Cost and No-load Cost exceed the respective reasonably expected costs and the Incremental Energy Offer is below $1,000 MWh, then the Composite Energy Offer shall equal $1,000/megawatt-hour and be composed of the resource's: (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $1,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is less than $1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

(c) If a generation resource that is an Eligible Fast-Start Resource submits a market-based offer that results in a Composite Energy Offer that exceeds $1,000/megawatt-hour at the resource's Economic Maximum:

(i) If the Incremental Energy Offer of the market-based schedule exceeds the Incremental Energy Offer of the associated cost-based offer, then the amortized Start-Up Cost and the amortized No-load Cost for the market-based schedule shall both be considered to exceed their respective reasonably expected costs, and the Composite Energy Offer shall be equal to $1,000/megawatt-hour and be composed of the resource's (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $1,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is less than $1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

(ii) If the Incremental Energy Offer of the market-based schedule is not greater than the Incremental Energy Offer of the associated cost-based offer and:

(1) If the amortized No-load Cost for the market-based schedule exceeds the No-load Cost specified on the associated cost-based offer or exceeds the reasonably expected cost of the No-load Cost of such cost-based offer, then the amortized No-load Cost shall be adjusted in the manner set forth in subsections (b)(iii)(2) and (4) above, as applicable.

(2) If the amortized Start-Up Cost for the market-based schedule exceeds the Start-Up Cost specified on the associated cost-based offer or exceeds the reasonably expected cost of the Start-Up Cost of such cost-based offer, then the amortized Start-Up Cost shall be adjusted in the manner set forth in subsections (b)(iii)(3) and (4) above, as applicable.

(3) To the extent the Composite Energy Offer resulting from subsections (c)(ii)(1) and (2) would exceed $2,000/MWh, then the Composite Energy Offer shall equal $2,000/megawatt-hour and the submitted Start-Up Cost and No-load Cost shall be adjusted in the manner set forth in subsection (e) below.

(d) For purposes of calculating Day-ahead Prices, the applicable marginal Incremental Energy Offer used in the calculation of Day-ahead Prices shall not exceed $2,000/megawatt-hour.

(e) If a generation resource that is an Eligible Fast-Start Resource submits an offer that results in a Composite Energy Offer with a maximum segment that exceeds $2,000/megawatt-hour and such offer is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted Start-Up Cost and

No-load Cost against the resource's reasonably expected Start-Up Cost and No-load Cost, the following adjustments will be made to cap the offer at no higher than $2,000/megawatt-hour:

(i) If the submitted Start-Up Cost and No-load Cost do not exceed the respective reasonably expected costs, the Composite Energy Offer shall equal $2,000/megawatt-hour and be composed of: (i) the resource's Incremental Energy Offer, (ii) to the extent the Incremental Energy Offer is less than $2,000/megawatt-hour, a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $2,000/megawatt-hour, and (iii) to the extent the sum of the foregoing is less than $2,000/megawatt-hour, a Start-Up Cost value an amortized Start-Up Cost value sufficient to make the Composite Energy Offer at Economic Maximum equal to $2,000/megawatt-hour.

(ii) If the submitted Start-Up Cost does not exceed the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does exceed the reasonably expected No-load Cost, then the Composite Energy offer shall equal the Incremental Energy Offer plus the amortized submitted Start-Up Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value greater than $2,000/megawatt-hour, then the Composite Energy Offer shall include an amortized Start Up Cost value sufficient to make the Composite Energy Offer equal to $2,000/megawatt-hour.

(iii) If the submitted Start-Up Cost exceeds the resource's reasonably expected Start-Up Cost but the submitted No-load Cost does not exceed the reasonably expected No-load Cost, then the Composite Energy Offer shall equal the Incremental Energy Offer plus the amortized No-load Cost; provided, however, if the resulting Composite Energy Offer at Economic Maximum yields a value greater than $2,000/megawatt-hour, then the Composite Energy Offer shall include an amortized No-load Cost value sufficient to make the Composite Energy Offer equal to $2,000/megawatt-hour.

(iv) If the submitted Start-Up Cost and No-load Cost both exceed the respective reasonably expected costs, the Composite Energy Offer shall equal the lesser of the resource's Incremental Energy Offer or $2,000/megawatt-hour.

(v) To the extent any of the foregoing subsections (e)(ii) through (e)(iv) would result in a Composite Energy Offer less than $1,000/MWh at Economic Maximum, the Composite Energy Offer shall equal $1,000/megawatt-hour and be composed of the resource's: (i) Incremental Energy Offer, (ii) a No-load Cost value equal to the lesser of the resource's amortized submitted No-load Cost or a value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum, and (iii) to the extent the sum of the foregoing is less than $1,000/megawatt-hour, an amortized Start-Up Cost value sufficient to make the Composite Energy Offer equal to $1,000/megawatt-hour at Economic Maximum.

(f) To the extent an Economic Load Response Participant resource's Composite Energy Offer is reviewed pursuant to Operating Agreement, Schedule 1, 6.4.3A, pursuant to which the Office of the Interconnection evaluates the resource's submitted shutdown cost against the resource's reasonably expected shutdown costs, adjustments may be applied to yield a Composite Energy Offer, at Economic Maximum, no lower than $1,000/megawatt-hour and no greater than $2,000/megawatt-hour as follows:

(i) If a Composite Energy Offer at Economic Maximum is greater than $1,000/megawatt-hour but does not exceed $2,000/megawatt-hour, and the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, does not exceed the resource's reasonably expected shutdown cost, then no adjustments shall be made to the submitted Composite Energy Offer.

(ii) If the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, exceeds the resource's reasonably expected shutdown cost, then the Composite Energy Offer shall equal: (i) the resource's Incremental Energy Offer, and (ii) to the extent the Incremental Energy Offer is less than $1,000/megawatt-hour, a shutdown value equal to the lesser of the resource's amortized submitted shutdown cost or a value sufficient to make the Composite Energy Offer at Economic Maximum equal to $1,000/megawatt-hour.

(iii) If the Composite Energy Offer at Economic Maximum exceeds $2,000/megawatt-hour and the amortized shutdown cost, to the extent that it is reviewed pursuant to Operating Agreement, Schedule 1, section 6.4.3A, does not exceed the resource's reasonably expected shutdown cost, then the Composite Energy Offer shall equal $2,000/megawatt-hour: (i) the resource's Incremental Energy Offer, and (ii) to the extent the Incremental Energy Offer is less than $2,000/megawatt-hour, a shutdown value sufficient to make the Composite Energy Offer equal to $2,000/megawatt-hour.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Operating Agreement, Schedule 1, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand

Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Operating Agreement, Schedule 1, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement consistent with the determination of the clearing price for each reserve product, and the components of Locational Marginal Prices referenced in Operating Agreement, Schedule 1, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minunte Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized

Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minure Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minure Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.5.2 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.11.6, resources will be paid for their energy output and Real-time Prices shall be determined on an hourly basis and applied to each Real-time Settlement Interval in the following manner:

i) If the Market Suspension is less than or equal to six (6) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be the average of Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

ii) If the Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours and there are cleared Day-ahead Prices for the affected Operating Day, then the Real-time Prices associated with such Market Suspension shall be the Day-ahead Prices for each corresponding hour. If no such Day-ahead Prices exist, then the Real-time Prices shall be the average of the Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

iii) If the Market Suspension is greater than twenty-four (24) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be determined based on the construction of an aggregate supply curve.

The aggregate supply curve shall be established as follows:

For online resources operating on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and compensation.

For online resources operating on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension. The selected cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and compensation.

For available offline resources, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension for the construction of the aggregate supply curve.

The summation of the actual generation MWs for on-line resources will be used as a proxy for demand. The energy component of Locational Marginal Price will be determined hourly from the supply curve at the intersection of supply and demand where the impact of constraints is not considered. The loss and congestion component of Locational Marginal Price will be set to zero dollars per megawatt-hour.

Self-scheduled resources will be included in the supply stack but with a zero dollar per megawatt-hour offer price, and will not be eligible to set price. Off-line resources and resources directed to lower their output to Economic Minimum will not be eligible to set price. Generation resources that may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability will not be eligible to set price.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

2.6.1 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.10.8(d), Day-ahead Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Price of zero dollars per megawatt-hour and all settlements will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

2.6A Interface Prices.

PJM shall from time to time, as appropriate, define and revise Interface Pricing Points for purposes of calculating LMPs for energy exports to or energy imports from external balancing authority areas. Such Interface Pricing Points may represent external balancing authority areas, aggregates of external balancing authority areas, or portions of any external balancing authority area. Subject to the terms of this section 2.6A, PJM may define Interface Pricing Points and interface pricing methods for a sub-area of a balancing authority area different from the pricing points and interface pricing methods applicable to the adjacent balancing authority area where the sub-area is located, and no action of the balancing authority area or any entity whose transactions do not source and/or sink within the sub-area shall affect the pricing points or interface pricing methods established for such sub-area. Definitions of Interface Pricing Points and price calculation methodologies may vary, depending on such factors as whether an external balancing authority area operates an organized electric market with locational pricing, whether the external balancing authority has entered an interregional congestion management agreement with PJM, and the availability of data from the external balancing authority area on such relevant items as unit costs, run status, and output. PJM shall negotiate in good faith with any external balancing authority that seeks to enter into an interregional congestion management agreement with PJM, and will file such agreement, upon execution, with the Commission. In the event PJM and an external balancing authority do not reach a mutually acceptable agreement, the external balancing authority may request, and PJM shall file with the Commission within 90 days after such request, an unexecuted congestion management agreement for such balancing authority. Nothing herein precludes PJM from entering into agreements with External Resource owners for the Dynamic Transfer of such resources, as contemplated by Operating Agreement, Schedule 1, section 1.12 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.12, at prices determined in accordance with such agreements. Acceptable pricing point definitions and pricing methodologies include, but are not limited to, the following:

(a) External Balancing Authority Areas that are Part of Larger Centrally Dispatched Organizations. PJM shall determine a set of nodes external to the PJM system representing an external balancing authority area or set of balancing authority areas via flow analysis, utilizing standard power flow analysis tools, of the impact of transactions from the balancing authority area or areas on the transmission facilities connecting PJM with such external area(s). PJM shall then weight the contribution of each identified node to the calculation of the interface price. For each Interface Pricing Point, a set of Tie Lines will be defined and each node in the interface definition will be assigned to a Tie Line. PJM shall utilize the sensitivity of the Tie Lines to an injection at each external pricing point to weight the node associated with that Tie Line in the Interface Pricing Point calculation, as more fully described in the PJM Manuals.

(b) External Areas that are Not Part of Larger Centrally Dispatched Organizations. PJM may define pricing points aggregating multiple directly or non-directly connected external balancing authority areas that are not part of larger centrally dispatched organizations. Prices at such points representing aggregated balancing authority areas shall be determined as described in subsection (a) above; provided, however, that PJM shall define Interface Pricing Points corresponding to individual, directly connected balancing authority areas, and establish alternative pricing methodologies for use as to such areas, to the extent that necessary supporting data is provided from the external area, as follows:

(1) PJM will define an Interface Pricing Point corresponding to a directly connected individual external balancing authority area or sub-area within a directly connected balancing authority area and determine prices in accordance with High-Low Pricing, as defined in section (A) below, if the balancing authority area or sub-area within the balancing authority area provides the data described in section (B) below.

(A) Under High-Low Pricing, the price for imports of energy to PJM from the external balancing authority area shall equal the LMP calculated by PJM at the generator bus in such area with an output greater than 0 MW that has the lowest price in such area; and the price for exports of energy from PJM to the external balancing authority area shall equal the price at the generator bus in such area with an output greater than 0 MW that has the highest price in such area, updated every 5 minutes in the real time market and calculated for each hour in the Day-Ahead market, to the extent and for the periods that the information described below is provided.

(B) Such pricing point and pricing methodology shall be provided only to the extent the external balancing authority area or sub-area provides or causes to be provided to PJM real-time telemetered load, generation and similar data for such area or sub-area demonstrating that the transaction receiving such pricing sources, or sinks as appropriate, in such area or sub-area. Such data shall be of the type and in the form specified in the PJM Manuals. If such data is provided, any transaction, regardless of participant, sourcing or sinking in such area will be priced in accordance with section (A) above. During any hour in which any entity makes any purchases from other external areas outside of such area or sub-area (other than delivery of external designated Network Resources or such other exceptions specifically documented for such area or sub-area in the PJM Manuals) at the same time that energy sales into PJM are being made, or purchases energy from PJM for delivery into such area or sub-area while sales from such area to other external areas are simultaneously implemented (subject to any exceptions specifically documented for such area or sub-area in the PJM Manuals), pricing will revert to the applicable import or export pricing point that would otherwise be assigned to such external area or sub-area.

(2) PJM will define an Interface Pricing Point corresponding to an individual external balancing authority area or sub-area within a directly connected balancing authority area and determine prices in accordance with Marginal Cost Proxy Pricing, as defined in section (A) below, if the balancing authority area or sub-area within a directly connected balancing authority area provides, in addition to the data specified in section (1)(B) above, the data described in section (B) below provided, however, that such pricing methodology shall terminate, and pricing shall be governed by the methodology described in subsection (a) or (b)(1) above, as applicable, on January 31, 2010 for any

external balancing authority area that has not executed an interregional congestion management agreement with the Office of the Interconnection prior to January 31, 2010.

(A) Under Marginal Cost Proxy Pricing, PJM shall compare the individual bus LMP for each generator in the PJM model in the directly connected balancing authority area or sub-area having a telemetered output greater than zero MW to the marginal cost for that generator.

In real time, during each 5-minute calculation of LMPs for the PJM Region, PJM shall calculate the energy price for imports to PJM from such area or sub-area as the lowest LMP of any generator bus in such area or sub-area with an output greater than 0 MW that has an LMP less than its marginal cost for such 5-minute interval. If no generator with an output greater than 0 MW has an LMP less than its marginal cost, then the import price shall be the average of the bus LMPs for the set of generators in such area with an output greater than 0 MW that PJM determines to be the marginal units in that area for that 5-minute interval. PJM shall determine the set of marginal units in the external area by summing the output of the units serving load in that area in ascending order of the units' marginal costs until such sum equals the real time load in such external area. Units in the external area with marginal costs at or above that of the last unit included in the sum shall be the marginal units for that area for that interval.

PJM similarly shall calculate the energy price for exports from PJM to such area or sub-area as the highest LMP of any generator bus in such area or sub-area with an output greater than 0 MW that has an LMP greater than its marginal cost for such 5-minute interval. If no generator with an output greater than 0 MW has an LMP greater than its marginal cost, then the export price shall be the average of the bus LMPs for the set of generators with an output greater than 0 MW that PJM determines to be the marginal units in such area for that 5-minute interval, as described above.

Locational interface prices in the Day-ahead Energy Market shall be calculated in the same manner as set forth above for the Real-time Energy Market, except that such prices will be determined on an hourly basis, utilizing information regarding whether each unit in such area is scheduled to run for each hour of the following day, provided as specified in subsection (B) below.

(B) Such pricing point and pricing methodology shall be provided only to the extent the external balancing authority area or sub-area provides or causes to be provided to PJM (i) unit-specific, real time telemetered output data for each unit in the PJM network model in such area or sub-area; (ii) unit-specific marginal cost data for each unit in the PJM network model in such area or sub-area, prepared in accordance with the PJM Manuals and subject to the same review of the Market Monitoring Unit as any such cost data for internal PJM units; and (iii) a day-ahead indication for each unit in such area or sub-area as to whether that unit is scheduled to run for each hour of the following day. During any hour in which any entity makes any purchases from other external areas outside of such area or sub-area (other than delivery of external designated Network Resources or such other exceptions specifically documented for such area or sub-area in the PJM Manuals) at the same time that energy sales into PJM are being made, or purchases energy from PJM for delivery into such area or sub-area while sales from such area to other external areas are simultaneously implemented (subject to any exceptions specifically documented for such area or sub-area in the PJM Manuals), pricing will revert to the applicable import or export pricing point that would otherwise be assigned to such external area or sub-area.

(C) PJM shall post the individual generator bus LMPs in the directly connected external control areas for informational purposes; provided, however, that no settlement shall take place at such external bus LMPs, and such nodes shall not be available for the submission of Virtual Transactions in the PJM Day-ahead Energy Market.

(3) All data provided to PJM by balancing and/or reliability authorities hereunder will be used only for the purpose of implementing the interface pricing set forth herein, will be treated confidentially by PJM, and will be afforded the same treatment provided to Member confidential data under the PJM Operating Agreement.

(4) PJM reserves the right to audit the data supplied to PJM hereunder by giving written notice to the relevant balancing/reliability authority/market operator no more than three months following provision of such data, and at least ten (10) business days in advance of the date that PJM wishes to initiate such audit, with completion of the audit occurring within sixty (60) days of such notice. Each party shall be responsible for its own expenses related to any such audit.

2.7 Performance Evaluation.

The Office of the Interconnection shall undertake an evaluation of the foregoing procedures for the determination of Locational Marginal Prices, as well as the procedures for determining and allocating Financial Transmission Rights and associated Transmission Congestion Charges and Credits, not less often than every two years, in accordance with the PJM Manuals. To the extent practical, the Office of the Interconnection shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The Office of the Interconnection shall report the results of its evaluation to the Market Participants, along with its recommendations, if any, for changes in the procedures. The Office of the Interconnection shall prepare reports, with regard to participation of Economic Load Response Participants in the PJM Interchange Energy Market, as required by the FERC and the PJM Manuals.

3. ACCOUNTING AND BILLING

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.1A Revenue Data for Settlements

(a) Revenue Data for Settlements are energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.

(b) Once a Market Participant submits five-minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five-minute basis.

(c) For generation resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection as adjusted in accordance with subsection (d). The revenue meter data for a generation resource can be either positive, representing energy injection, or negative, representing an energy withdrawal.

(d) Revenue Data for Settlements for generation resources for which Market Participants submit hourly revenue meter data to the Office of the Interconnection shall be calculated as follows:

i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour plus an offset. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the sum of the absolute value of the Real-time Settlement Interval telemetry or State Estimator values for the hour).

ii) If the difference between the average of the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, and further described in the PJM Manuals, for an hour and the hourly revenue meter data is greater than 20 percent of the hourly revenue meter data and greater than 10 MW, then the Revenue Data for Settlements is a flat profile of the hourly revenue meter data equally apportioned over the five minute intervals in the hour.

iii) If a Market Participant is unable to provide telemetry for a generation resource, the Revenue Data for Settlements will be a flat profile of the hourly revenue meter data equally apportioned over the five-minute intervals in the hour.

(e) For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is the submitted value to the Office of the Interconnection adjusted for any curtailment and flat profiled over the set of five-minute intervals that the energy transaction is scheduled and dispatched.

(f) For demand response resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.

(g) For load, the Revenue Data for Settlements is the hourly submitted value to the Office of the Interconnection and flat profiled equally apportioned over the five-minute intervals in the hour.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource’s expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource’s expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market performance-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the Regulation market performance-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market performance-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = \underset{\delta=0 \text{ to } 5\text{ Min}}{\mathbf{r}_{\text{Signal,Response}(\delta,\delta+5\text{ Min})}};$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate an energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the Real-time Settlement Interval accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

(l) During a Market Suspension where the suspension is less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource’s Regulation clearing cost is determined by the summation of their Regulation offer and opportunity cost. The opportunity cost will be based on the resource’s cost-based offer and will be determined as follows:

For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.

For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation accuracy score cannot be calculated during a Market Suspension, the 100-hour rolling average accuracy score will be used for the Market Suspension period.

(ii) If the regulation mileage ratio cannot be calculated during a Market Suspension, the mileage ratio will be set to one (1) for the Market Suspension period.

(iii) If the unit-specific benefits factor cannot be calculated during a Market Suspension, the unit-specific benefits factor would be based on the historical average unit-specific benefits factor over past hours that shared the same penetration of Regulation D resources that exist for the given Market Suspension hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all

Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the

Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Secondary Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in section 3.2.3(q) below, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp\_Request_t = {(Dispatchtarget_{t-1} - AOutput_{t-1})}\Big/{(LAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + (Ramp\_Request_t * Case\_Eff\_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh –Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic Load Response Participant resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating

Day. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1, section 3.2.3(h)(ii)(A) to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource’s output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection’s signals and instructions from the generation resource’s expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource’s output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource’s output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection’s signals and instructions from the generation resource’s expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource’s unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, in excess of amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response

Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant’s total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour (“Non-Synchronized Reserve Obligation”). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant’s hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant’s behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating

Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multipled by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants’ response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time

Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$(A + B) – (C + D + E + F)$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant’s real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant’s spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant’s real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant’s spot market purchases or decreases its spot market sales, and (ii) each Market Participant’s energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant’s real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant’s spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant’s internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 [Reserved]

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, the following formula shall be used to determine a Peak Shaving Adjustment end-use customer's demand reductions when determining peak shaving performance rating as described in PJM Manual 19, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be either:

(i) any weekday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

(ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:

a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant’s compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Tariff, Attachment K-Appendix, section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten Business Days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where (Delta LMP x MWh consumed) > (LMP_{NEW} x DR), where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW}).

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15^{th} day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k), and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJMSettlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in Tariff, Attachment K-Appendix, section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in Tariff, Attachment K-Appendix, section 3.2.3(o), the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with Tariff, Attachment K-Appendix, section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE **i** in zone **z** shall be $\mathbf{RTL_{iz}/(RTL + X)}$
and the ratio share for party **j** shall be $\mathbf{X_j/(RTL + X)}$.

Where:

RTL is the total real time load in all zones where LMP ≥ Net Benefits Test price;

$\mathbf{RTL_{iz}}$ is the real-time load for LSE **i** in zone **z**;
X is the total export quantity from PJM in that hour; and
$\mathbf{X_j}$ is the export quantity by party **j** from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with Tariff, Attachment K-Appendix, section 3.2.3. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in Tariff, Attachment K-Appendix, section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of section 3.3A.7(a) shall not be eligible for settlement pursuant to sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on on-site generation data if the On-Site Generator is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Tariff, Attachment K-Appendix, section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the end-use customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring end-use customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this section 3.3A.8. The Office of the Interconnection may refer the matter to the

PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or buses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges and Transmission Loss Charges as specified in Section 5 of this Schedule.

3.5.4 Billing.

PJMSettlement on behalf of PJM shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

3.6 Metering Reconciliation.

3.6.1 Meter Correction Billing.

Metering errors and corrections will be reconciled at the end of each month by a meter correction charge (positive or negative). The monthly meter correction charge for tie meter corrections shall be the product of the positive or negative deviation in energy amounts, times the real-time Settlement Interval load weighted average real-time Locational Marginal Price for all intervals of that month for all load buses in the PJM Region. The monthly meter correction charge for generator meter corrections, including Pseudo-Tie generator imports into the PJM Region, shall be the product of the positive or negative deviation in energy amounts, times the Real-time Settlement Interval generation weighted average Locational Marginal Price at that generator's bus for all intervals of that month.

The monthly meter correction charge for Dynamic Schedule imports into the PJM Region, and non unit-specific Dynamic Schedule exports out of the PJM Region, shall be the product of the positive or negative deviation in energy amounts and the Dynamic Schedule's weighted average interface real-time Locational Marginal Price at the applicable Interface Pricing Point for all hours of that month.

The monthly meter correction charge for Pseudo-Tie generator exports and unit-specific Dynamic Schedule exports out of the PJM Region shall be the product of the positive or negative deviation in energy amounts and the difference between the weighted average interface real-time Locational Marginal Price at the applicable Interface Pricing Point, and the generation weighted average Locational Marginal Price at that generator's bus, for all hours of that month.

3.6.2 Meter Corrections Between Market Participants.

If a Market Participant or the Office of the Interconnection discovers a meter error affecting an interchange of energy with another Market Participant and makes the error known to such other Market Participant prior to the completion by the Office of the Interconnection of the accounting for the interchange, and if both Market Participants are willing to adjust hourly load records to compensate for the error and such adjustment does not affect other parties, an adjustment in load records may be made by the Market Participants in order to correct for the meter error, provided corrected information is furnished to the Office of the Interconnection in accordance with the Office of the Interconnection's accounting deadlines. No such adjustment may be made if the accounting for the Operating Day in which the interchange occurred has been completed by the Office of the Interconnection. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participants experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied to the Market Participants. For Market Participants that are Electric Distributors that request the debit and credit to be further allocated to all Network Service Users in their territory (as documented in the PJM Manuals), where all Load Serving Entities in the respective Electric Distributor territory agree, the appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the applicable territory.

3.6.3 500 kV Meter Errors.

Billing shall be adjusted to account for errors in meters on 500 kV Transmission Facilities within the PJM Pre-Expansion Zones (excluding Allegheny Power) or between the PJM Pre-Expansion Zones (excluding Allegheny Power) and Allegheny Power. The Market Participant with the tie meter or generator meter experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied among Electric Distributors that report hourly net energy flows from metered Tie Lines in the Pre-Expansion Zones (excluding Allegheny Power) in proportion to the load consumed in their territories. The error shall be accounted for by a correction at the end of the billing cycle. For Market Participants that are Electric Distributors that request the debit and credit to be further allocated to all Network Service Users in their territory (as documented in the PJM Manuals), where all Load Serving Entities in the respective Electric Distributor territory agree, the appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the applicable territory. Such allocation shall not include purchases of Direct Charging Energy.

3.6.4 Meter Corrections Between Control Areas.

An error between accounted for and metered interchange between a Party in the PJM Region and an entity in a Control Area other than the PJM Region shall be corrected by adjusting the hourly meter readings. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participant with ties or Dynamic Transfers with such other Control Area experiencing the error shall account for the full amount of the discrepancy. However, if the meter correction applies to a tie on the 500 kV system between the PJM Pre-Expansion Zones (excluding Allegheny Power) and other Control Areas, Electric Distributors that report hourly net energy flows from metered Tie Lines in the Pre-Expansion Zones (excluding Allegheny Power) shall account for the full amount of the discrepancy in proportion to the load consumed in their territories. The appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the PJM Region. Such allocation shall not include purchases of Direct Charging Energy. The Office of the Interconnection will adjust the actual or scheduled interchange between the other Control Area and the PJM Region to maintain a proper record of inadvertent energy flow.

3.6.5 Meter Correction Data.

Meter error data shall be submitted to the Office of the Interconnection not later than the last Business Day of the month following the end of the monthly billing cycle applicable to the meter correction.

3.6.6 Correction Limits.

A Market Participant may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter error shall be limited to bills for transactions occurring in the most recent annual accounting period of the billing Market Participant in which the meter error occurred, and the prior annual accounting period.

3.7 Inadvertent Interchange.

Inadvertent Interchange will be reconciled each hour by a charge allocation (positive or negative) applied to Network Service Users in proportion to their deliveries to load in the PJM Region, which shall be the product of the positive or negative Inadvertent Interchange amount times the PJM load weighted average Locational Marginal Price for that hour. Such allocation shall not include purchases of Direct Charging Energy.

3.8 Market-to-Market Coordination

The Office of the Interconnection shall charge or credit a Market Participant for the transmission congestion from the Market Participant's Pseudo-Tie generator within MISO to the PJM-MISO interface resulting from market-to-market coordination pursuant to this Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8. The Office of the Interconnection shall calculate such charges and credits for the Real-time Energy Market for each Pseudo-Tie generator using the following formulas.

$RT\ Charge\ /\ Credit_{PT} = RT\ CLMP_{PT} * DevMW_{PT}$

Where:

$RTCLMP_{PT} = \sum RT\ ShadowPrice_{FG} * (RT\ ShiftFactor_{FG,PT} – RT\ ShiftFactor_{FG,Interface})$

$RTCLMP_{PT} =$	Real-time congestion LMP for the path from the Pseudo-Tie generator to the MISO-PJM common interface.
$RT\ ShadowPrice_{FG} =$	Real-time shadow price for each M2M Flowgate calculated in accordance with the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.
$RT\ ShiftFactor_{FG,PT} =$	Real-time shift factor for the Pseudo-Tie generator and each M2M Flowgate.

Where:

$DevMW_{PT} = (RT\ MW_{PT} – DA\ MW_{PT})$

$DevMW_{PT} =$	The megawatt deviation between the cleared megawatts in the Day-ahead Energy Market and Real-time Energy Market megawatt output for a Pseudo-Tie generator.
$RT\ MW_{PT} =$	Real-time Energy Market megawatt output for the Pseudo-Tie generator.
$DA\ MW_{PT} =$	Cleared and committed megawatts for a Pseudo-Tie generator in the Day-ahead Energy Market.

The dollars refunded to or collected from the Pseudo-Tie generator will be, respectively, distributed from or added to the Balancing Congestion Charges fund.

4. [Reserved For Future Use]

5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

If a dollar-per-MW-hour value is applied in a calculation under this section 5.1 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission congestion resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission congestion resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant location at which the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant’s Transmission Congestion Charge is equal to the difference between the total day-ahead transmission congestion withdrawal charge calculated in subsection (b) and the total day-ahead transmission congestion injection credit calculated in subsection (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJMSettlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each Real-time Settlement Interval, Market Participants shall be assessed for Transmission Congestion Charges (positive or negative) in accordance with the following equation:

$$[(A – B) * C] – [(D – E) * C]$$

Where:

A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Congestion Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

(g) The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Transmission Congestion Charges under subsection (f).

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy using such Transmission Service.

(a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

(b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during the applicable constrained settlement interval for the delivery of energy on the scheduled path.

(a) For each Day-ahead Settlement Interval, Transmission Congestion Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point.

(b) For each Real-time Settlement Interval, Transmission Congestion Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time transactions used to calculate Transmission Congestion Charges under this subsection (b).

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in the applicable settlement interval multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Reserved.

5.1.7 Reserved.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in *s*ection 5.2.1(b), each FTR Holder shall receive as a Transmission Congestion Credit a proportional share of the Day-ahead Energy Market Transmission Congestion Charges collected for each constrained hour.

(b) If an Effective FTR Holder between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in *section* 7 of this Schedule 1) and had a *Virtual Transaction portfolio which includes* Increment Offer*(s),* Decrement Bid*(s), and/or Up-to Congestion Transaction(s)* that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market*, whereby the Effective FTR Holder's Virtual Transaction portfolio resulted in (i) a difference in Location Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses which is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, and (ii) an increasing the value between such delivery and receipt buses, then the Market Participant shall not receive any Transmission Congestion Credit* associated with such Financial Transmission Right in such hour, *that is attributable to the absolute value (i.e., the product of the constraint's shadow price times the distribution factor (dfax) of the difference between the Financial Transmission Right delivery and receipt buses) of the relevant Day-ahead Energy Market binding constraint (as further discussed in section 5.2.1(c) below), but no more than the* excess of one divided by the number of hours in the applicable *period* multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction *(i.e., FTR profit). For the purposes of this calculation, every individual Financial Transmission Right of an Effective FTR Holder shall be considered*.

(c) For purposes of *s*ection 5.2.1(b)*, an Effective FTR Holder's Virtual Transaction portfolio shall be considered if the absolute value of the attributable net flow across a Day-ahead Energy Market binding constraint relative to the Day-ahead Energy Market load weighted reference bus between the Financial Transmission Right delivery and receipt buses exceeds the physical limit of such binding constraint by the greater of 0.1 MW or ten percent*.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and Tariff, Attachment M-Appendix, section VI. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in Tariff, Attachment M-Appendix, section VI. An Effective FTR Holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Operating Agreement, Schedule 1, section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the FTR Holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the FTR Holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the FTR Holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the FTR Holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC’s rules related to its FTR reporting tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this

Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the FTR Holder shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction

Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Operating Agreement, Schedule 1, section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than sixty percent (60%) of a Network Service User’s proportion of peak load in the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to Operating Agreement, Schedule 1, section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Operating Agreement, Schedule 1, section 5.2.2(f) of this Schedule.

(h) Reserved.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each FTR Holder shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR Holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR Holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total

Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

During a Market Suspension where there are no Day-ahead Prices available for the affected Operating Day, the aforementioned Day-ahead Congestion Price will be substituted with the hourly integrated Real-time Congestion Price as determined in Operating Agreement, Schedule 1, section 2.5.

For a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are no Day-ahead Prices available for the affected Operating Day, the Day-ahead Financial Transmission Right Target Allocation values would be equal to zero for the hours corresponding to this suspension interval.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the Day-ahead Energy Market Transmission Congestion Charges in each hour. If the total of the Target Allocations is less than or equal to the total of the Day-ahead Energy Market Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Day-ahead Energy Market Transmission Congestion Charges shall be distributed as described below in Operating Agreement, Schedule 1, section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the Day-ahead Energy Market Transmission Congestion Charges for the hour, each FTR Holder shall be assigned a share of the Day-ahead Energy Market Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR Holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR Holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to Operating Agreement, Schedule 1, section 7.4.4(c) and shall be allocated to all FTR Holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies

determined pursuant to Operating Agreement, Schedule 1, section 7.4.4(c)] – [sum of the total monthly excess ARR revenues and excess Day-ahead Energy Market Transmission Congestion Charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Day-ahead Energy Market Transmission Congestion Charges accumulated in a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Day-ahead Energy Market Transmission Congestion Charges received by the FTR Holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Day-ahead Energy Market Transmission Congestion Charge distribution described in Operating Agreement, Schedule 1, section 5.2.6(a) is performed, any excess Day-ahead Energy Market Transmission Congestion Charges remaining at the end of a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Day-ahead Energy Market Transmission Congestion Charges received by the FTR Holder during the current Planning Period, including previously distributed excess Day-ahead Energy Market Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Day-ahead Energy Market Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Day-ahead Energy Market Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all ARR holders on a pro-rata basis according to the total Target Allocations for all ARRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an ARR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all ARRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Day-ahead Energy Market Transmission Congestion Charge credit to each Market Participant that held an ARR at any time during the Planning Period in accordance with the following formula: {[total excess Day-ahead Energy Market Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all ARRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all ARRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.7 Allocation of Balancing Congestion Charges

At the end of each hour during an Operating Day, the Office of the Interconnection shall allocate the Balancing Congestion Charges to real-time load and exports on a pro-rata basis. Such allocation shall not include purchases of Direct Charging Energy.

During a Market Suspension where the suspension has no Day-ahead Prices or if the suspension is less than or equal to twenty-four (24) hours, which may span up to two Operating Days, and there are no Day-ahead Prices available for the affected Operating Day, for each hour corresponding to this suspension interval, the Office of the Interconnection shall allocate the Balancing Congestion Charges to Financial Transmission Right Target Allocation values before being allocated to real-time load and exports on a pro-rata basis.

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the Office of the Interconnection and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the Balancing Congestion Charges that are distributed in accordance with Operating Agreement, Schedule 1, section 5.2.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule.

(b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(c) If a dollar-per-MW-hour value is applied in a calculation under this section 5.4 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

5.4.3 Network Service User and Market Participant Calculations.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases.

(b) For each Day-ahead Settlement Interval, Market Participants shall be charged for transmission losses resulting from all Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant location at which both the Market Participant withdraws energy and such energy is priced.

(c) For each Day-ahead Settlement Interval, Market Participants shall be reimbursed for transmission losses resulting from all Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant location at which both the Market Participant injects energy and such energy is priced.

(d) The day-ahead component of a Market Participant’s Transmission Loss Charge is equal to the difference between the total day-ahead transmission loss withdrawal charge calculated in paragraph (b) and the total day-ahead transmission loss injection credit calculated in paragraph (c).

(e) (i) The amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available.

The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered Tie Lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJMSettlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load contracts, including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold POLR auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the POLR Suppliers based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) For each real-time Settlement Interval, Market Participants shall be assessed for transmission losses charges (positive or negative) in accordance with the following equation:

$$[(A – B) * C] – [(D – E) * C]$$

Where:
A = The Market Participant Energy Withdrawal megawatts in real-time at the location at which both the Market Participant withdraws energy and such energy is priced;

B = The Market Participant Energy Withdrawal megawatts in day-ahead at the location at which both the Market Participant withdraws energy and such energy is priced;

C = Real-time Loss Price;

D = The Market Participant Energy Injection megawatts in real-time at the location at which both the Market Participant injects energy and such energy is priced; and

E = The Market Participant Energy Injection megawatts in day-ahead at the location at which both the Market Participant injects energy and such energy is priced.

(g) The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate transmission losses charges under subsection (f).

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using such Transmission Service.

(a) For each Day-ahead Settlement Interval, Transmission Loss Charges shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source interface at the boundary of the PJM Region.

(b) For each Real-time Settlement Interval, Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region. For each Real-time Settlement Interval, a Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region.

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path for the applicable interval.

(a) For each Day-ahead Settlement Interval, Transmission Loss Charges shall be assessed for the transaction MWh scheduled in the Day-ahead Energy Market, calculated as the scheduled amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point.

(b) For each Real-time Settlement Interval, Transmission Loss Charges shall be assessed for real-time MWh in excess of the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time MWh falling below the amounts scheduled for the applicable interval in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time transactions used to calculate Transmission Loss Charges under this subsection (b).

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule and in accordance with the PJM Manuals.

5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

5.6 Transmission Constraint Penalty Factors

5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. If a Market Suspension greater than twenty-four (24) consecutive hours is declared in the Real-time Energy Market as per Operating Agreement, Schedule 1, section 2.5.2, Transmission Constraint Penalty Factors shall not be used to determine the Marginal Value of a transmission constraint. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

5.6.2 Default Transmission Constraint Penalty Factor Values

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market when determining the day-ahead security constrained economic dispatch, known as the dispatch run, and $2,000/MWh in the determination of Day-ahead Prices in the pricing run. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of $1,000/MWh or a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

5.6.3 Modifications to Transmission Constraint Penalty Factor Values

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price + Loss Price + Congestion Price (all binding constraints)} - \text{Incremental Energy Offer*}}{D_{fax}}$$

Where D_{fax} equals the distribution factor of the resource for the transmission constraint

*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

(c) Notwithstanding the provisions of this section 5.6, and until such time the rebuild of the Lanexa-Dunnsville-Northern Neck line in the Dominion Transmission Zone is complete (as confirmed with the Transmission Owner and subsequently reported on the transmission facilities outage list posted on the Office of the Interconnection's website), the Office of the Interconnection shall set the transmission line limit in its Security Constrained Economic Dispatch program at a level that ensures the offers of the resources being used to control the constraint are reflected in the Congestion Price in lieu of applying a Transmission Constraint Penalty Factor when there are insufficient available resources to relieve a transmission constraint on the remaining transmission facilities serving the Northern Neck peninsula caused by the Lanexa-Dunnsville-Northern Neck line outage.

6. “MUST-RUN” FOR RELIABILITY GENERATION

6.1 Introduction.

The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

6.2 Identification of Facility Outages.

Not later than one hour prior to the deadline specified in Section 1.10.1 of this Schedule, the Office of the Interconnection shall identify on the PJM Open Access Same-Time Information System any facility outage or other system condition which it has determined may give rise to a transmission constraint that may require, in order to maintain system reliability, the dispatch of one or more generation resources that otherwise would not be dispatched based on the merits of their offers to the PJM Interchange Energy Market.

6.3 Dispatch for Local Reliability.

6.3.1 Request and Dispatch.

In addition to the dispatch of generation by the Office of the Interconnection to maintain reliability on transmission facilities monitored by it, a Member that owns or leases with rights equivalent to ownership local Transmission Facilities, as defined in this Agreement and the Consolidated Transmission Owners Agreement and that operates a local control center in accordance with Section 11.3.3 of this Agreement or a Market Operations Center in accordance with Section 1.7.5 of this Schedule may request the Office of the Interconnection to dispatch generation in order to maintain reliability on any such local Transmission Facilities that are not then monitored by the Office of the Interconnection, subject to the rules and procedures in Section 6.3.2 and the PJM Manuals. The Office of the Interconnection shall dispatch generation to maintain reliability on such local Transmission Facilities by incorporating the facilities in the State Estimator program described in Section 2.3 as set forth below, unless the Office of the Interconnection determines that such dispatch would adversely affect reliability in the PJM Region or would otherwise not be in accordance with Good Utility Practice.

6.3.2 Designation of Local Transmission Facilities.

The following rules and procedures shall apply to a Member request that the Office of the Interconnection dispatch generation on one or more local Transmission Facilities that are not then directly monitored by the Office of the Interconnection.

(a) The local Transmission Facilities that are the subject of the request for monitoring and dispatch control must be among the facilities that comprise the Transmission System under the PJM Tariff and must meet the PJM Reliability Planning Criteria set forth in the PJM Manuals;

(b) The Member shall provide modeling information for such local Transmission Facilities and provide sufficient telemetry to the Office of the Interconnection such that power flows are observable by the State Estimator program described in Section 2.3;

(c) The request for monitoring and dispatch control of local Transmission Facilities shall constitute a request that such local Transmission Facilities become and remain monitored by the Office of the Interconnection and subject to its dispatch control for a period of not less than one year;

(d) Requests under this Section for monitoring and dispatch control of local Transmission Facilities may be made only annually pursuant to the procedures set forth in the PJM Manuals;

(e) The Office of the Interconnection shall post all requests for monitoring and dispatch control of local Transmission Facilities made under this Section on the PJM Internet site; and

(f) The Member shall comply with all other operating procedures established by the Office of the Interconnection regarding dispatch for local reliability as set forth in the PJM Manuals.

6.3.3 Transition Procedures for Local Transmission Facilities under the Monitoring Responsibility and Dispatch Control of the Office of the Interconnection as of June 1, 2002.

The Office of the Interconnection shall determine whether local Transmission Facilities under its monitoring responsibility and dispatch control as of June 1, 2002 meet the PJM Reliability and Planning Criteria. Members with such local Transmission Facilities that do not meet the PJM Reliability Planning Criteria must either (1) remove the local Transmission Facilities from the dispatch control and monitoring responsibility of the Office of the Interconnection within 60 days of notification by the Office of the Interconnection of its determination that the local Transmission Facilities do not meet the PJM Reliability and Planning Criteria; or (2) commit, at their own cost and by a completion date agreed to by the Office of the Interconnection and the Member, to reinforce the local Transmission Facilities to enable the local Transmission Facilities to meet the PJM Reliability and Planning Criteria. This commitment to reinforce the local Transmission Facilities is subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, provided that, in the event that a Member cannot reinforce the local Transmission Facilities due to the unavailability of required financing, the local Transmission Facilities must be removed from the monitoring responsibility and dispatch control of the Office of the Interconnection within 60 days of the determination that required financing is unavailable. The local Transmission Facilities will remain under the monitoring and dispatch control of the Office of the Interconnection during the construction of the reinforcements.

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest overall system production cost. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal (“three pivotal supplier test”). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource’s market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor (“dfax”) has an absolute value equal to or greater than the dfax used by the Office of the Interconnection’s system operators when evaluating the impact of generation with respect to the constraint (“effective megawatts”) will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax (“effective costs”). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at the time of commitment,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of \$2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus up to the lesser of 10% of such costs or \$100 MWh, the sum of which shall not exceed \$2,000/MWh; and, for offers greater than \$2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped ("Frequently Mitigated Unit" or "FMU"), and for which the unit's market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus $20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a “Frequently Mitigated Unit” because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit’s Projected PJM Market Revenues plus the unit’s PJM capacity market revenues on a rolling 12-month basis, divided by the unit’s MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an “Associated Unit” upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology,

without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU’s average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =
[(Maximum Allowable Operating Rate$_i$) – (Bid Production Cost $_{i-1}$)] / (MW$_i$ – MW$_{i-1}$)

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate ($/hour @ MW) =

$$[(\text{Heat Input}_i @ \text{MW}_i) \times (\text{Performance Factor}) \times (\text{Fuel Cost})] \times (1 + A)$$

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource’s operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller’s PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource’s actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost ($/hour @ MW) =
$$\left[\sum_{i=1}^{n} (\text{MW}_i - \text{MW}_{i-1}) \times (\text{P}_i) - \frac{1}{2} \times \text{UBS} \times (\text{MW}_i - \text{MW}_{i-1}) \times (\text{P}_i - \text{P}_{i-1})\right] + \text{No-Load Cost}$$

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller’s cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of $1,000/megawatt-hour or the offer price of the most expensive verified segment on the Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller’s cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to $1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer’s costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer’s incremental costs; and

(ii) The end use customer’s incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant’s, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Operating Agreement, Schedule 1, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Station Service Cost] x (1 +A)

Where:

Start Fuel =

For units without a soak process, “Start Fuel” shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, “Start Fuel” is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller’s PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource’s actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Operating Agreement, Schedule 1, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Operating Agreement, Schedule 1, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in

Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds \$1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer’s costs in providing such demand reduction are greater than \$1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer’s incremental costs and shutdown costs; and

(ii) The end use customer’s incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant’s, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to \$1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

6.5 [Reserved for Future Use]

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Such offers must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such cost-based offers (“parameter limited schedules”) shall be considered in the commitment of a resource when the Market Seller does not pass the three pivotal supplier test, as further described in Operating Agreement, Schedule 1, section 6.4.1 and the parallel provisions in Tariff, Attachment K-Appendix, section 6.4.1.

(b) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations (“parameter limited schedules”). Such market-based parameter limited schedules must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such market-based parameter limited schedules shall be considered in the commitment of a resource under the following circumstances:

(i) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.

(ii) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations during the period of June 1 through September 30; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations during the period of June 1 through September 30; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations during the period of June 1 through September 30, for all, or any part, of an Operating Day.

(c) For the 2014/2015 through 2017/2018 Delivery Years for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2018/2019 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan, parameter limited schedules shall be defined for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts.

For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and for the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (i) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.

(d) [Reserved]

(e) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in Tariff, Attachment M-Appendix, section II.B.1, the Office of the Interconnection shall file to revise the Parameter Limited Schedule Matrix in section 6.6(d) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate.

(f) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with Tariff, Attachment M-Appendix, section II.B. The default values set forth in the table in subsection (d) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (i) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.

(g) For the 2016/2017 Delivery Year and subsequent Delivery Years, the following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the

Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;

(ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;

(iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,

(iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Have combined start-up and notification times that shall not exceed one hour; and,

(ii) Have a minimum down time that shall not exceed one hour.

(h) For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Combined start-up and notification times shall not exceed 48 hours;

(ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and,

(iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.

(i) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

(i) Temporary Exceptions. A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Failure to provide a timely response to such request for additional information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of any updates to the physical condition of the unit and shall notify the Office of Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one Business Day prior to the early termination date. A Market Seller shall provide supporting documentation demonstrating the actual termination date of the physical and actual parameter limitation that prompted the need for the temporary exception to the Office of Interconnection and the Market Monitoring Unit within one Business Day of the termination of such condition. A temporary exception may only be requested one-time for the same physical and actual constraint per occurrence since an operational constraint that may periodically exist more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Tariff, Attachment M-Appendix, section II.B, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 Business Days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) Period Exceptions and Persistent Exceptions. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market

Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection’s determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller’s request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 Business Days after receipt of the Market Seller’s notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

(1) for generating units for which no megawatts of the unit are commited as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years,

(2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years,

(3) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years,

(4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and

(5) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years.

(i) Notwithstanding the foregoing, the provisions of this section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner’s obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(k) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(l) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

6A [Reserved For Future Use]

6A.1 [Reserved For Future Use]

6A.2 [Reserved For Future Use]

6A.3 [Reserved For Future Use]

7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; and (2) any single calendar month period remaining in the Planning Period. With the exception of FTRs allocated pursuant to Operating Agreement, Schedule 1, section 5.2.2 (e) and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to Operating Agreement, Schedule 1, section 7.1.1(b), in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. Weekend on-peak, weekday on-peak, off-peak and 24-hour Financial Transmission Rights, as those products are described in Operating Agreement, Schedule 1, section 7.3.4, will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to Operating Agreement, Schedule 1, section 5.2.2(e) and the award of Financial Transmission Rights pursuant to Operating Agreement, Schedule 1, section 7.1.1(b). Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; and (ii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction. An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to Operating Agreement, Schedule 1, section 7.1.1, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five Business Days and shall be conducted sequentially. Each round shall begin with the bidding period. The bidding period for annual Financial Transmission Rights auctions shall be open for three consecutive Business Days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time), subject to extension of the bidding period in accordance with Tariff, Attachment K-Appendix, section 7.3.5(e). Monthly Financial Transmission Rights auctions shall be held each month. The bidding period for monthly Financial Transmission Rights auctions shall be open for three consecutive Business Days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time), subject to extension of the bidding period in accordance with Tariff, Attachment K-Appendix, section 7.3.5(e).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Day-ahead Energy Market Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual Financial Transmission Rights auction conducted pursuant to Operating Agreement, Schedule 1, section 7.1, the Office of the Interconnection shall conduct a long-term Financial Transmission Rights auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term Financial Transmission Rights auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term Financial Transmission Rights auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process, including Auction Revenue Rights made available in which transmission facilities which were modeled out of service in the annual Auction Revenue Rights allocations return to service, are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction. Additionally, residual annual Auction Revenue Rights that become available through incremental capability created by future transmission upgrades as further described in the PJM Manuals shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction. The long-term Financial Transmission Rights auction model shall include all upgrades planned to be placed into service on or before June 30th of the first Planning Period within the three year period covered by the auction. The transmission upgrades to be modeled for this purpose shall only include those upgrades that, individually, or together, have 10% or more impact on the transmission congestion on an individual constraint or constraints with congestion of $5 million or more affecting a common congestion path. Transmission upgrades modeled for this purpose also will be modeled in the subsequent long-term Financial Transmission Rights auction, as further detailed in the PJM Manuals. Residual Auction Revenue Rights created by an increase in transmission capability due to future transmission upgrades, as specified above, are determined only for modeling purposes and will not be allocated to Market Participants.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of five rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 2 months after the first round. The third round shall be conducted approximately 2 months after the second round. The fourth round shall be conducted approximately 2 months after the third round, and the fifth round shall be conducted approximately 3 months after the fourth round. In each round 20 percent of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three Business Days ending at 5:00 p.m. on the last day, subject to extension of the bidding period in accordance with Tariff, Attachment K-Appendix, section 7.3.5(e). PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five Business Days after the close of the bidding period for each round unless circumstances beyond PJM's control prevent PJM from meeting the applicable deadline. Under such circumstances, PJM will post the auction results at the earliest possible opportunity. If the Office of the Interconnection discovers a potential error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the Business Day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the second Business Day following the initial publication of prices for that auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

(i) The periods covered by long-term Financial Transmission Rights auctions shall be any single Planning Period within the three Planning Period term covered by the relevant auction.

(ii) Weekend on-peak, weekday on-peak, off-peak and 24-hour Financial Transmission Rights, as those products are described in Operating Agreement, Schedule 1, section 7.3.4, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights auction. Eligible receipt and delivery points in long-term Financial Transmission Rights auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.2 Financial Transmission Rights Characteristics.

7.2.1 Reconfiguration of Financial Transmission Rights.

Through an appropriate linear programming model, the Office of the Interconnection shall reconfigure the Financial Transmission Rights offered or otherwise available for sale in any auction to maximize the value to the bidders of the Financial Transmission Rights sold, provided that any Financial Transmission Rights acquired at auction shall be simultaneously feasible in combination with those Financial Transmission Rights outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum MW quantities of the bids and offers, select the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

7.2.2 Specified Receipt and Delivery Points.

The Office of the Interconnection will post the list of available receipt and delivery points for each Financial Transmission Rights Auction before the start of the bidding window. Auction bids for annual Financial Transmission Rights Obligations may specify as receipt and delivery points any combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points. Auction bids for annual Financial Transmission Rights Options may specify as receipt and delivery points such combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points as the Office of the Interconnection shall allow from time to time as set forth in PJM Manual 06: Financial Transmission Rights. Auction bids for Financial Transmission Rights submitted in the monthly auctions may specify as receipt and delivery points any combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points for bids that cover any month beyond the next month. Auction bids for Financial Transmission Rights submitted in the monthly auctions that cover the single calendar month period immediately following the month in which the monthly auction is conducted may specify any combination of available receipt and delivery buses represented in the State Estimator model for which the Office of the Interconnection calculates and posts Locational Marginal Prices. Auction bids may specify available receipt and delivery points from locations outside of the PJM Region to locations inside such region, from locations within the PJM Region to locations outside such region, or to and from locations within the PJM Region.

7.2.3 Transmission Congestion Charges.

Financial Transmission Rights shall entitle holders thereof to credits only for Day-ahead Energy Market Transmission Congestion Charges, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than PJMSettlement.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Any Financial Transmission Rights auctions conducted to liquidate a defaulting Member's Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in section 7.3.9 below, and as may be further described in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Operating Agreement, Schedule 1, section 5.2.2 (e), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 Weekend On-Peak, Weekday On-Peak, Off-Peak and 24-Hour Periods.

Weekend on-peak, weekday on-peak, off-peak and 24-hour Financial Transmission Rights will be offered in the annual , long-term,and monthly auctions. Weekend on-peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending 11:00 p.m. on Saturdays, Sundays, and holidays as defined in the PJM Manuals. Weekday on-peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on all days. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for a weekend on-peak, weekday on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Operating Agreement, Schedule 1, section 7.1.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offeror or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Operating Agreement, Schedule 1, section 7.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.2.2, and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period, market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

(e) In the event of extraordinary circumstances affecting the submission of bids within the bidding period in which the Office of the Interconnection determines it necessary to extend the bidding period, the Office of the Interconnection shall notify Market Participants as soon as possible of the new bidding period ending day and time.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Operating Agreement, Schedule 1, section 7.5, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5, and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints. Financial Transmission Rights with a zero clearing price will only be awarded if there is a minimum of one binding constraint in the auction period for which the Financial Transmission Rights path sensitivity is non-zero. Financial Transmission Right Options with a market-clearing price less than one dollar will not be awarded.

7.3.7 Announcement of Winners and Prices.

Within two (2) Business Days after the close of the bidding period for an annual Financial Transmission Rights auction round, and within five (5) Business Days after the close of the bidding period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded unless circumstances beyond PJM's control prevent PJM from meeting the applicable deadline. Under such circumstances, PJM will post the auction results at the earliest possible opportunity. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the Business Day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second Business Day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

For a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are no Day-Ahead Prices available for the affected Operating Day, the Financial Transmission Right auction costs would be zero in proportion to the number of hours of the Market Suspension in the Operating Day.

7.3.9 Addressing Defaulting Member's Financial Transmission Rights.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the Operating Agreement or Tariff, the Office of the Interconnection shall, as soon as practicable after declaring the Member to be in default as provided in Operating Agreement, section 15.1.5, use reasonable efforts to initiate within two applicable auctions the following procedures to settle, liquidate or otherwise resolve each Financial Transmission Rights position held by the defaulting Member:

a) The Office of the Interconnection shall unilaterally terminate all of the defaulting Member's rights with respect to forward Financial Transmission Rights positions as of the date of the Member's default.

b) As to each Financial Transmission Rights position held by the defaulting Member immediately prior to the termination of the defaulting Member's rights under subsection (a) above, the Office of the Interconnection shall determine and execute an appropriate course of action for addressing such Financial Transmission Rights position, based on the specific circumstances of the default as determined by the Office of the Interconnection in exercise of its reasonable judgment, such as (1) liquidating the position by offering it for sale in an upcoming applicable Financial Transmission Rights auction, (2) liquidating the position by offering it for sale in an auction called and scheduled for the specific purpose of liquidating one or more positions held by the defaulting Member ("Special Auction"), (3) allowing the position to go to settlement, or (4) another course of action the Office of the Interconnection determines to be appropriate under the circumstances that is designed to minimize potential losses to PJM Members. The Office of the Interconnection will provide reasonable advance notice to PJM Members of the approach or course of action it has determined to be appropriate prior to implementing that approach or course of action. The Office of the Interconnection is not required to apply a single approach to the defaulting Member's entire Financial Transmission Rights portfolio, and may determine that the appropriate course of action for addressing a defaulting Member's portfolio includes a combination of the above approaches as applied to different positions within the defaulting Member's overall Financial Transmission Rights portfolio.

c) The Office of the Interconnection will seek to minimize the losses to PJM Members associated with settling, liquidating or otherwise resolving the defaulting Member's Financial Transmission Rights portfolio and may base its determination in subsection (b) above on several factors, including but not limited to, the following:

1) the Office of the Interconnection's assessment of which approach will provide the greatest degree of protection to the financial integrity of the PJM Markets;

2) the size of the defaulting Member's Financial Transmission Rights portfolio, both in absolute terms and relative to overall market volume;

3) the term of the Financial Transmission Rights positions held by the defaulting Member as considered for a single position or on a portfolio basis;

4) whether liquidation is feasible or not, and on what timeline, due to the cessation or curtailment of trading at PJM for all Financial Transmission Rights or a subset of Financial Transmission Rights positions;

5) prevailing market conditions, such as but not limited to market liquidity and volatility; and

6) timing of the default and the actions taken to address the default.

d) Special Auctions. The Office of the Interconnection shall administer each Special Auction provided for in subsection (b)(2) above according to the procedures set forth in the Tariff and PJM Manuals for FTR auctions to the extent appropriate in the Office of the Interconnection's sole discretion, and may adopt special rules for each Special Auction to accommodate the unique circumstances underlying the particular default and particular Financial Transmission Rights positions being liquidated, with the terms and conditions of such auction being determined with the goal of facilitating a successful auction in light of the particular positions to be auctioned, the prevailing market conditions for such open positions (including the depth, scope, and nature of participation in such markets), and such other factors as the Office of the Interconnection determines appropriate, including those factors enumerated in subsection (c) above. The Office of the Interconnection shall provide reasonable advance notice to FTR Participants of a Special Auction and the terms and conditions under which it will be conducted.

e) All liquidations made pursuant to subsection (b) above shall be for the account of the defaulting Member (and all amounts owed PJM in respect thereof shall be included in amounts owed by the defaulting Member as part of its default).

f) Notwithstanding subsections 7.3.9(a) and (b) above, the actual net charges or credits resulting from the defaulting Member's Financial Transmission Rights positions for which PJMSettlement acted as counterparty as calculated through the normal settlement processes shall be included in calculating the Default Allocation Assessment charges as described in Operating Agreement, section 15.2.2.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with Operating Agreement, Schedule 1, section 7.4.4. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to Operating Agreement, Schedule 1, section 7.4.3(b). If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) In accordance with Operating Agreement, Schedule 1, section 5.2.6.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.
>
> (ii) Long-term FTR auction revenues remaining after distributions made pursuant to Operating Agreement, Schedule 1, section 7.4.1(d)(ii) shall be distributed pursuant to Operating Agreement, Schedule 1, section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers a *potential* error in the allocation, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the Business Day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the second Business Day following the publication of the initial allocation. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the Active Historical Generation Resources or Qualified Replacement Resources , and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. Active Historical Generation Resources shall mean those historical resources that were designated to be delivered to load based on the historical reference year, and which have not since been deactivated and, further, only up to the current installed capacity value of such resource as of the annual allocation of ARRs for the target PJM Planning Period. Qualified Replacement Resources shall mean those resources the Office of the Interconnection designates for the ensuing Planning Period to replace historical resources that no longer qualify as Active Historical Generation Resources and that maximize the economic value of ARRs while maintaining Simultaneous Feasibility, as further described in the PJM Manuals.

Prior to the stage 1A of the allocation process, the Office of the Interconnection shall determine, for each Zone, the amount of megawatts of ARRs available from Active Historical Generation Resources in that Zone and the amount of megawatts required from Qualified Replacement Resources. The Office of the Interconnection shall designate Qualified Replacement Resources as follows, and as further described in the PJM Manuals. Qualified Replacement Resources shall be either from a (1) capacity resource that has been included in the rate base of a specific Load

Serving Entity in a particular Zone, using criteria for rate-based as specified in sections 7.6 and 7.7 hereof concerning New Stage 1 Resources and Alternative Stage 1 Resources; or (2) from a non-rate-based capacity resource.

Prior to the end of each PJM Planning Period the Office of the Interconnection will determine which Stage 1 Resources are no longer viable for the next PJM Planning Period and then will replace such source points with Qualified Replacement Resources (i.e., Capacity Resources that pass the Simultaneous Feasibility Test and which are economic). The Office of Interconnection will determine the replacement source points as follows. First, the Office of the Interconnection will compile a list of all Capacity Resources that are operational as of the beginning of the next Planning Period, that are not currently designated as source points and will post such list on the PJM website prior to finalizing the Stage 1 eligible resource list for each transmission zone for review by Market Participants. In the first instance, all such resources will be considered to be non-rate-based. Market Participants will be asked to review the posted resource list and provide evidence to the Office of the Interconnection, if any, of the posted resources that shall be classified as rate-based resources. Once the replacement resource list along with the resource status is finalized after any input from Market Participants, the Office of the Interconnection will create two categories of resources for each Stage 1 transmission zone based on economic order: one for rate-based; and a second for non-rate-based resources. When determining economic order, the Office of the Interconnection will utilize historical source and sink Day-ahead Energy Market Congestion Locational Marginal Prices (“CLMPs”). Historical value will be based on the previous three years’ CLMP sink versus CLMP source differences weighted by 50% for the previous calendar year, weighted by 30% for the year prior and weighted by 20% for the year prior. To the extent replacement resources do not have three years’ worth historical data, weighting will be performed either 50/50% in the case of two years or 100% in the case of one year worth of historical data. If a full year of historical data is not available, PJM will utilize the CLMP from the closest electrically equivalent location to compose an entire year of historical data. Once the economic order is established for each Stage 1 zonal rate-based and non-rate-based generator categories, the Office of the Interconnection will begin to replace Stage 1 zonal retirements with the Qualified Replacement Resources by first utilizing rate-based resources in the economic order while respecting transmission limitations. And once the rate-based resource determination is concluded, the Office of the Interconnection will then utilize non-rate-based resources, in economic order, while respecting transmission limitations as described previously.

The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; 2018 for the OVEC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than *sixty percent (60%) of* the Network Service User's *proportion of peak load in the* Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the
megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. *In stage 1B,*

valid Auction Revenue Right source buses include Active Historical Resources, Qualified Replacement Resources, Zones, hubs and external Interface Pricing Points.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of *two* rounds with up to one *half* of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will *source and sink*. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. *Valid Auction Revenue Rights sink buses include only Zones, generators, hubs and external Interface Pricing Points.* The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus *to each sink bus*. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one *half* of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Firm Point-to-Point Transmission Service, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one *half* of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one *half* of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible unless such infeasibility is caused by extraordinary circumstances. Such increased limits shall be included in all rounds of the annual allocation and auction processes and in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (i) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (i), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Service customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Service customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one *half* of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

(k) PJM Transmission Customers taking firm transmission service for the delivery of Direct Charging Energy to Energy Storage Resources or to Open-Loop Hybrid Resources are not eligible for allocation of Auction Revenue Rights.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its FTR reporting tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.6.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.5 Simultaneous Feasibility.

(a) The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate powerflow models of contingency-constrained dispatch. Simultaneous feasibility determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction that are not inconsistent with the determination of the deliverability of Generation Capacity Resources under the Reliability Assurance Agreement. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Day-ahead Energy Market Transmission Congestion Charges to satisfy all Financial Transmission Rights Obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights Obligations. To ensure revenue sufficiency, the powerflow model used for simultaneous feasibility determinations is a markets model that uses flows caused by sources and sinks of requested Auction Revenue Rights (including Incremental Auction Revenue Rights) or Financial Transmission Rights, as well as market limits (as described in section (b) below) to determine the capability available to accommodate financial rights that are simultaneously feasible. The markets model differs from both an operations model, which uses physical generators or load, and a planning model, which uses expected physical generators or load.

(b) Simultaneous feasibility determinations pursuant to this section utilize applicable market limits. Market limits may differ from physical facility ratings to reflect expected market capability and to align expected Financial Transmission Rights total target allocations with expected congestion, and to ensure sufficient revenues are collected from the Day-ahead Energy Market Transmission Congestion Charges to satisfy all Financial Transmission Rights obligations. To account for historical market impacts, market limits may reflect (without limitation) such factors as requested and awarded Auction Revenue Rights, Incremental Auction Revenue Rights and Financial Transmission Rights, uncompensated powerflow, external flowgate entitlements or limits, transfer limits of the type appropriate for reactive interfaces, operational considerations, voltage limitations and/or closed loop interfaces. Market limits also are based on reasonable assumptions about the configuration and availability of transmission capability during the study period, including (without limitation) scheduled or expected transmission outages. The market limits are applied to facilities modeled in an Auction Revenue Rights allocation, Financial Transmission Rights auction or Incremental Auction Revenue Rights study and may result in operative constraints that establish different limits than physical (e.g., thermal or voltage) ratings. As used here, an operative constraint results when a market limit binds in the powerflow model and constrains the grant of Auction Revenue Rights, Incremental Auction Revenue Rights or Financial Transmission Rights.

(c) On an annual basis the Office of the Interconnection shall conduct a simultaneous feasibility test for stage 1A Auction Revenue Rights, which shall assess the simultaneous feasibility for each year remaining in the term of the right(s). This test shall be based on the Auction Revenue Rights required to meet sixty percent (60%) of peak load in each Zone requirements. The Office of the Interconnection shall apply a zonal load growth rate to the simultaneous feasibility test for the ten year term of the stage 1A Auction Revenue Rights to reflect load growth as estimated by the Office of the Interconnection.

(d) Simultaneous feasibility tests for new stage 1 resource requests made pursuant to Section 7.6 of Schedule 1 of this Agreement shall ensure that the request for a new base resource does not increase the megawatt flow on facilities binding in the current Auction Revenue Rights allocation or in future stage 1A allocations and does not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions. The most limiting set of conditions will be used as the limiting condition in these evaluations. A simultaneous feasibility test conducted pursuant to this section by the Office of the Interconnection shall assess the simultaneous feasibility under the following conditions:

(i) Based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs.

(ii) Based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

(e) Simultaneous feasibility tests for Incremental Auction Revenue Rights requested pursuant to Operating Agreement, Schedule 1, section 7.8 and Tariff, Part VI, Subpart C, section 231 shall ensure that the request for the Incremental Auction Revenue Rights does not increase the megawatt flow on facilities binding in the current Auction Revenue Rights allocation or in future stage 1A allocations and does not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions. The most limiting set of conditions will be used as the limiting conditions in these evaluations. A simultaneous feasibility test conducted pursuant to this section by the Office of the Interconnection shall assess the simultaneous feasibility using the following models derived from the markets model:

(i) An Incremental Auction Revenue Rights model that is based on the existing allocation year with transmission outages removed (i.e., the transmission assumed out of service in the base markets model is assumed to be in service). All existing stage 1 and stage 2 Auction Revenue Rights are modeled as fixed injection withdrawal pairs.

(ii) A 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

(f) Simultaneous feasibility tests pursuant to section (e) above utilize a transfer analysis to determine the flow impacts. The transfer analysis is performed by injecting at the source and withdrawing at the sink and measuring the impacts on the facilities. Additional details are provided in the PJM Manuals and related explanatory materials posted on the PJM website such as the PJM Whitepaper entitled “PJM Incremental Auction Revenue Rights Model Development and Analysis.”

7.6 New Stage 1 Resources.

A Network Service User may request the addition of new stage 1 resources to the stage 1 resource list if the capacity of the Stage 1 generation resources for a Zone determined pursuant to Section 7.4.2(b) is less than sixty percent (60%) of the of peak load in the Zone. Requests made pursuant to this section shall be subject to Section 7.5(c) of Schedule 1 of this Agreement and shall be limited to generation resources either owned by the requesting party or those subject to a bona fide firm energy and capacity supply contracts where such contract is executed by the requesting party to meet load obligations for which it is eligible to receive stage 1 Auction Revenue Rights and remains in force and effect for a minimum term of ten (10) years.

7.7 Alternate Stage 1 Resources.

A Network Service User may replace one or more of its existing stage 1 resources and its associated megawatt amount of Auction Revenue Rights determined pursuant to Section 7.4.2(b) with an alternate resource. It the Network Service User making such request accepts the megawatt amount of Auction Revenue Rights associated with the alternate resource as established by the Office of the Interconnection, the alternate resource shall replace the relevant existing stage 1 resource prospectively beginning with the next annual Auction Revenue Rights allocation. If the Network Service User making such request rejects the megawatt amount of Auction Revenue Rights established by the Office of the Interconnection for the alternate resource, the Auction Revenue Rights associated with the original stage 1 resource shall remain in effect for the Network Service User. Requests made pursuant to this section shall be subject to the following:

- Requests made pursuant to this section shall be subject to Section 7.5(c);
- Eligible alternate resources shall be limited to generation resources owned by the requesting party or bona fide firm energy and capacity supply contracts that meet the requirements set forth in Section 7.6 of Schedule 1 of this Agreement;
- Alternate resources shall be of an electrically equivalent megawatt amount, which means that relative to the existing resource, the alternate resource cannot consume a greater amount of transmission capability on facilities binding in the current Auction Revenue Rights allocation or future stage 1A allocations, and cannot allow megawatt flow(s) to exceed applicable ratings on any other facilities;
- The total amount of requested alternate stage 1 Auction Revenue Rights cannot exceed the original awarded stage 1 megawatt amounts of Auction Revenue Rights associated with the original historical resource as determined pursuant to Section 7.4.2(b).

7.8 Elective Upgrade Auction Revenue Rights.

(a) In addition to any Incremental Auction Revenue Rights established under the PJM Tariff, any party may elect to fully fund Network Upgrades to obtain Incremental Auction Revenue Rights pursuant to this section, provided that Incremental Auction Revenue Rights granted pursuant to this section shall be simultaneously feasible with outstanding Auction Revenue Rights, which shall include stage 1 and stage 2 Auction Revenue Rights, and against stage 1A Auction Revenue Right capability for the future 10 year period, as determined by the Office of the Interconnection pursuant to Section 7.8(b) of Schedule 1 of this Agreement. A request made pursuant to this section shall specify a source, sink and megawatt amount, where the source and sink each meet the criteria described for stage 1 in Operating Agreement, Schedule 1, sections 7.4.2(b) and 7.4.2(c).

(b) The Office of the Interconnection shall assess the simultaneous feasibility of the requested Incremental Auction Revenue Rights and the outstanding Auction Revenue Rights against the existing base system Auction Revenue Right capability and stage 1A Auction Revenue Right capability for the future 10 year period pursuant to Operating Agreement, Schedule 1, section 7.5. This preliminary assessment will determine the incremental flow impact necessary on facilities.

(c) The incremental flow impact represents the incremental capability required on a facility to ensure the requested Incremental Auction Revenue Rights can be made feasible. This required capability is used to determine the upgrades required to accommodate the requested Incremental Auction Revenue Rights and ensure all outstanding Auction Revenue Rights are simultaneously feasible. Additional details are provided in the PJM Manuals and related explanatory materials posted on the PJM website such as the PJM Whitepaper entitled "PJM Incremental Auction Revenue Rights Model Development and Analysis."

(i) For Incremental Auction Revenue Rights requests, the Office of the Interconnection shall use an Incremental Auction Revenue Rights model to perform the simultaneous feasibility test detailed in Operating Agreement, Schedule 1, section 7.5. The Incremental Auction Revenue Rights model shall consist of an Incremental Auction Revenue Rights model and the 10 year stage 1A Auction Revenue Rights model. An Incremental Auction Revenue Rights model uses the same transmission system model used in the annual Auction Revenue Rights process, except any modeled transmission outages included in the Auction Revenue Rights process are removed (i.e., the transmission assumed out of service in the base markets model is assumed to be in service). Auction Revenue Rights requests that were denied or pro-rated in the annual Auction Revenue Rights allocation as a result of assumed transmission outages also are restored in the Incremental Auction Revenue Rights model because the transmission is assumed to be in service for purposes of this model.

(ii) If the incremental market flows created by the Incremental Auction Revenue Rights request cause facilities to be limited or increase the market flow on already limited facilities in either the Incremental Auction Revenue Rights model or the

10 year stage 1A Auction Revenue Rights model, increased system capability will be required in order for the Office of the Interconnection to grant the Incremental Auction Revenue Rights request. This required incremental capability is used to determine the upgrades required to accommodate the requested Incremental Auction Revenue Rights and ensure all outstanding Auction Revenue Rights (including any pro-rated but restored Auction Revenue Rights requests) are simultaneously feasible. Additional details are provided in the PJM Manuals and related explanatory materials posted on the PJM website such as the PJM Whitepaper entitled "PJM Incremental Auction Revenue Rights Model Development and Analysis."

(iii) In addition to the Incremental Auction Revenue Rights model, the Office of the Interconnection uses a planning model that consists of the Regional Transmission Expansion Plan model used by the Office of the Interconnection to study system needs and proposed projects five years forward combined with modeled in-service and planned generation and forecasted load. The planning model includes transmission system upgrades that are ahead of the proposed Incremental Auction Revenue Rights request in the New Services Queue. The upgrades required for the Incremental Auction Revenue Rights request must achieve additional incremental capability over and above any planned baseline or Supplemental Project upgrades, including upgrades related to a Supplemental Project with a projected in-service date later than the applicable planning case year.

(d) If a party elects to fund upgrades to obtain Incremental Auction Revenue Rights pursuant to this section, no less than forty-five (45) days prior to the in-service date of the relevant upgrades, as determined by the Office of the Interconnection, the Office of the Interconnection shall notify the party of the actual amount of Incremental Auction Revenue Rights that will be granted to the party based on the allocation process established pursuant to Section 231 of Part VI of the Tariff.

(e) Incremental Auction Revenue Rights established pursuant to this section shall be effective for the lesser of thirty (30) years, or the life of the project, from the in-service date of the Network Upgrade(s). At any time during this thirty-year period (or the life of the Network Upgrade whichever is less), in lieu of continuing this thirty-year Auction Revenue Right, the owner of the right shall have a one-time choice to switch to an optional mechanism, whereby, on an annual basis, it will have the choice to request an Auction Revenue Right during the annual Auction Revenue Rights allocation process between the same source and sink, provided the Auction Revenue Right is simultaneously feasible. A party that is granted Incremental Auction Revenue Rights pursuant to this section may return such rights at any time, provided that the Office of the Interconnection determines that it can simultaneously accommodate all remaining outstanding Auction Revenue Rights following the return of such Auction Revenue Rights. In the event a party returns Incremental Auction Revenue Rights, it shall retain no further rights regarding such Incremental Auction Revenue Rights.

(f) No Incremental Auction Revenue Rights shall be granted pursuant to this section if the costs associated with funding the associated Network Upgrades are included in the rate base of a public utility and on which a regulated return is earned.

7.9 Residual Auction Revenue Rights.

(a) As necessary in each Planning Period PJM shall calculate Residual Auction Revenue Rights for Auction Revenue Rights pathways that were prorated pursuant to section 7.4.2(h) of Schedule 1 of this Agreement. Residual Auction Revenue Rights calculated pursuant to this section shall be determined prior to the increase in transmission capability, including the return to service of existing transmission capability, that creates the Residual Auction Revenue Rights.

(b) Network Service Users and Qualifying Transmission Customers allocated stage 1 Auction Revenue Rights pursuant to Operating Agreement, Schedule 1, sections 7.4.2(a)-(c) that were subject to proration pursuant to Operating Agreement, Schedule 1, section 7.4.2(h) shall be eligible to receive Residual Auction Revenue Rights. Residual Auction Revenue Rights shall be allocated pursuant to the following schedule:

(i) The initial allocation of Residual Auction Revenue Rights shall be to holders of prorated stage 1A Auction Revenue Rights in an amount equal to the difference between the allocated stage 1A Auction Revenue Rights and the requested stage 1A Auction Revenue Rights.

(ii) Residual Auction Revenue Rights remaining after an allocation made pursuant to Operating Agreement, Schedule 1, section 7.9(b)(i) shall be allocated to holders of prorated stage 1B Auction Revenue Rights in an amount equal to the difference between the allocated stage 1B Auction Revenue Rights and the requested stage 1B Auction Revenue Rights.

(iii) Residual Auction Revenue Rights remaining after allocations made pursuant to Operating Agreement, Schedule 1, sections 7.9(b)(i) and (ii) shall not be allocated to any entity and shall not be considered by the Office of the Interconnection in its administration of Operating Agreement, Schedule 1, section 7.

(c) The sum of a Network Service User's and Qualifying Transmission Customer's Residual Auction Revenue Rights awarded pursuant to this section and its stage 1 and 2 Auction Revenue Rights awarded in an annual allocation shall not exceed the entity's peak load.

(d) Residual Auction Revenue Rights awarded pursuant to this section shall be effective on the first day of the month in a Planning Period the increase in transmission capability creating the Residual Auction Revenue Rights is included in the administration of Operating Agreement, Schedule 1, section 7.1.1(a).

(e) Residual Auction Revenue Rights awarded pursuant to this section shall be subject to Operating Agreement, Schedule 1, section 7.4.2(e).

(f) The value of Residual Auction Revenue Rights awarded pursuant to this section, determined as specified in Operating Agreement, Schedule 1, section 7.4.3(b), shall be positive. Negatively valued Residual Auction Revenue Rights will not be awarded.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM

8.1 Emergency Load Response and Pre-Emergency Load Response Program Options

The Emergency Load Response Program and Pre-Emergency Load Response Program are designed to provide a method by which end-use customers may be compensated by PJM for reducing load immediately prior to an anticipated emergency event ("pre-emergency event") or during an emergency event. As used in the Emergency Load Response Program and Pre-Emergency Load Response Program, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program and Pre-Emergency Load Response Program:

- Full Program Option

  Participants in the Full Program Option receive, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency event or emergency event measured as set forth in the Reporting and Compliance provisions below.

- Energy Only Option

  Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

8.2 Participant Qualifications

Two primary types of distributed resources are candidates to participate in the PJM Emergency Load Response Program and Pre-Emergency Load Response Program:

On-Site Generators (As defined in Operating Agreement, section 1)

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

Only Members or Special Members may participate in the Emergency Load Response Program and Pre-Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response and Pre-Emergency Load Response Program provisions herein, including, but not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member or Special Member may participate in the Emergency Load Response Program and Pre-Emergency Load Response Program on behalf of non-members as the Curtailment Service Provider. All payments are made to the PJM Member or Special Member in such case. Curtailment Service Providers must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** However, for Special Members the $5,000 annual member fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications.

Special Members are limited to be PJM Market Sellers;
Voting privileges and sector designation are waived;
Thirty day notice for waiting period is waived;
Requirement for 24/7 control center coverage is waived;
No PJM-supported user group capability is permitted.

To participate in the Emergency Load Response Program and Pre-Emergency Load Response Program, the Demand Resource must:

Be capable of reducing at least 100 kW of load;
Be capable of receiving notification of a Load Management Event.
The location shall not be Critical Natural Gas Infrastructure.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

(a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or

(b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

(a) Metering equipment used for retail electric service;

(b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM in accordance with the requirements herein and in the PJM Manuals; or

(c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.4 Registration

1. Curtailment Service Providers must complete the applicable PJM Load Response Program Registration Form ("Registration Form") that is posted on the PJM website (www.pjm.com) for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company ten Business Day review period, as described herein, Curtailment Service Providers shall submit completed Registration Forms to the Office of the Interconnection no later than one day before the tenth Business Day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery Year shall be rejected by the Office of the Interconnection. To the extent that a completed Registration Form is submitted to the Office of the Interconnection prior to one day before the tenth Business Day preceding the relevant Delivery Year and such registration is rejected by the electric distribution company or the Office of the Interconnection because of incorrect data on the Registration Form, such registration may be resubmitted by the Curtailment Service Provider before May 31st preceding the relevant Delivery Year, but such registration will be rejected by the Office of the Interconnection unless the electric distribution company has verified the registration on or before May 31st preceding the relevant Delivery Year. Incomplete Registration Forms will be rejected by the Office of the Interconnection; Curtailment Service Providers may not resubmit registrations that were rejected for being incomplete unless they are able to do so no later than one day before the tenth Business Day preceding the relevant Delivery Year. The following general steps will be followed:

2. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. The Curtailment Service Provider completes the Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response or Pre-Emergency Load Response Program participant, PJM shall notify the appropriate electric distribution company of an Emergency Load Response and Pre-Emergency Load Response Program participant's registration and request verification as to whether the load that may be reduced is subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response Programs pursuant to the process described below. The electric distribution company has ten Business Days to respond. An electric distribution company which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company asserts has not been satisfied) an end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. If evidence provided by an electric distribution company to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after May 31st preceding the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

b. In the absence of a response from the electric distribution company within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response Programs, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response and Pre-Emergency Load Response Program requirements.

c. For those registrations terminated pursuant to this section, all Emergency Load Response and Pre-Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJM in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. The Curtailment Service Provider completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response and Pre-Emergency Load Response participant, PJM shall notify the appropriate electric distribution company of an Emergency Load Response and Pre-Emergency Load Response participant's registration and request verification as to whether the load that may be reduced is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company has ten Business Days to respond. If the electric distribution company verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company asserts has been satisfied) to participate in the Emergency Load Response Program and Pre-Emergency Load Response Program, then the electric distribution company must provide to the Office of the Interconnection within the referenced ten Business Day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration on or before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

b. In the absence of a response from the electric distribution company within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with all of the Emergency Load Response and Pre-Emergency Load Response Program requirements, including the registration section, the Emergency Load Response and Pre-Emergency Load Response participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response and Pre-Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency Load Response and Pre-Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

4. PJM will inform the requesting Curtailment Service Provider of acceptance into the Emergency Load Response Program and Pre-Emergency Load Response Program and notify the appropriate electric distribution company of the requesting Curtailment Service Provider’s acceptance into the program or notifies the requesting Curtailment Service Provider and appropriate electric distribution company of PJM’s rejection of the requesting participant’s registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

8.5 Pre-Emergency Operations

All participants in the Pre-Emergency Load Response Program shall be subject to the operation procedures herein, unless the participant can demonstrate its Demand Resource Registration: (1) relies on Behind the Meter generation to fulfill its load reduction obligations; (2) the Demand Resource Registration has environmental restrictions imposed on it by Applicable Laws and Regulations that limit the Demand Resource Registration's ability to operate only in emergency conditions; and (3) such limitation exists for any period of time. For the purposes of Section 8, emergency conditions shall be defined either by the express terms of the Applicable Law or Regulation, or if not set forth therein shall be deemed to exist if PJM has declared a NERC Energy Emergency Alert Level 2, as defined in the applicable NERC Standards. If these three criteria are met, the participant shall be subject to the emergency operation procedures contained in Section 8.6. In such case, the Curtailment Service Provider shall submit a request for the relevant Demand Resource Registration(s) to be an emergency (versus pre-emergency) Demand Resource Registration to the Office of the Interconnection, at the time the registration is submitted in applicable PJM system in accordance with this Agreement. A Curtailment Service Provider shall not submit a request for an exception unless it has done its due diligence to confirm that the Demand Resource Registration meets the requirements referenced herein and has obtained from the end-use customer documentation supporting the exception request. The Curtailment Service Provider shall provide the Office of the Interconnection with a copy of such supporting documentation within three (3) Business Days of a request therefor. Failure to provide such supporting documentation by the deadline shall result in the Demand Resource Registration being subject to the pre-emergency procedures herein.

PJM will initiate a pre-emergency event prior to the declaration of a Maximum Generation Emergency or an emergency event when practicable. A pre-emergency event is implemented when economic resources are not adequate to serve load and maintain reserves or maintain system reliability, and prior to proceeding into emergency procedures. Understanding the primary responsibility of the Office of the Interconnection to maintain system security, the Office of the Interconnection will strive to exhaust, but it is not obligated to exhaust, all economic resources prior to initiating a pre-emergency event. PJM will initiate an electronic message to Curtailment Service Providers notifying them of the pre-emergency event; Curtailment Service Providers are required to have the capability to retrieve this electronic message as described in the PJM Manuals. Additionally, PJM will post the pre-emergency event information on the PJM website and issue a separate All-Call message.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the availability, location, minimum notification time, dispatch price and/or quantity of load reduction needed, subject to transmission constraints in the PJM Region. To give PJM dispatchers the flexibility to address reliability concerns in the most effective and timely manner and invoke the resources that offer the most assurance of effective relief of emergency conditions, the dispatch of Demand Resource Registrations may not be based solely on the least-cost resources since such dispatch shall be based not only on price, but also on availability, location, minimum notification time and/or quantity of megawatts of load or load reduction needed.

The dispatch price of Full Program Option registrations and Energy Only Option registrations in the Pre-Emergency Load Response Program are eligible to set the real time Locational Marginal Prices ("LMP") when the Office of the Interconnection has implemented pre-emergency procedures and such registrations are required to reduce demand in the PJM Region and as described in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix. Energy Only Option registrations must also satisfy PJM's telemetry requirements.

Curtailment Service Providers with Demand Resource Registrations in the Emergency Load Response and Pre-Emergency Load Response Programs must provide real-time operational data regarding the availability and status of their resources to PJM, and comply with operational procedures, as described in detail in the PJM Manuals.

8.6 Emergency Operations

PJM will initiate the notification of a Load Management Event coincident with the declaration of Maximum Generation emergency. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) The minimum duration of a load reduction request is one hour. A Load Management Event is implemented whenever economic generating capacity is not adequate to serve load and maintain reserves or maintain system reliability. PJM will initiate an electronic message to Curtailment Service Providers notifying them of the Load Management Event; Curtailment Service Providers are required to have the capability to retrieve this electronic message as described in the PJM Manuals. Additionally, PJM will post the Load Management Event information on the PJM website and issue a separate All-Call message.

Following PJM’s request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the availability, location, minimum notification time, dispatch price and/or quantity of load reduction needed, subject to transmission constraints in the PJM Region. To give PJM dispatchers the flexibility to address reliability concerns in the most effective and timely manner and invoke the resources that offer the most assurance of effective relief of emergency conditions, the dispatch of Demand Resource Registrations may not be based solely on the least-cost resources since such dispatch shall be based not only on price, but also on availability, location, minimum notification time and/or quantity of megawatts of load or load reduction needed.

The dispatch price of Full Program Option registrations and Energy Only Option registrations in the Emergency Load Response Program are eligible to set the real time LMP when the Office of the Interconnection has implemented Emergency procedures and such registrations are required to reduce demand in the PJM Region and as described in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix. Energy Only Option registrations must also satisfy PJM’s telemetry requirements.

Curtailment Service Providers with Demand Resource Registrations in the Emergency Load Response and Pre-Emergency Load Response Programs must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations***.

8.7 Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the Load Management Event. If the data are not received within 60 days, no payment for participation shall be provided. Meter data must be provided for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the electric distribution company upon receipt, and these parties will then have ten (10) Business Days to provide feedback to PJM.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency or Pre-Emergency registration. Compensation will be provided for reductions in energy consumption during emergency events, tests and associated retest(s), where applicable by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2.01 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource Registration dispatched by PJM for actual, achieved reductions for an emergency event is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource Registration.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing Operating Reserve charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping dispatch hours for an aggregate registration (i.e., multiple locations on the same registration) or dispatch groups where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for tests and for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Tariff, Attachment DD and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

The cost of payments for Emergency Load Response and Pre-Emergency Load Response energy settlements for tests, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for that month where the tests were conducted, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be RTLiz/(RTL + X)
and the ratio share for party j shall be Xj/(RTL + X).
Where:

RTL is the total real time load in all zones where Load Management was tested;
RTLiz is the real-time load for LSE i in zone z;
X is the total export quantity from PJM in that hour; and

Xj is the export quantity by party j from PJM.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

8.9 Reporting and Compliance

Actual load reductions of Energy Only Option emergency registrations will be added back for the purpose of peak load calculations for capacity for the following Delivery Year.

Actual Emergency Load Response, Pre-Emergency Load Response and Economic Load Response load reductions for Demand Resource Registrations in the Emergency Load Response or Pre-Emergency Load Response Full Program Option or Capacity Only Option which occur during a registration's product-type required availability window as set forth in PJM Reliability Assurance Agreement, Tariff and Manuals or which occur outside the availability window if such registration received Bonus Performance for Performance Assessment Interval(s) or responded to economic event will be added back for the purpose of calculating peak load for capacity for the following Delivery Year, as set forth in the PJM Manuals and consistent with the load response recognized for capacity compliance as set forth in the Reporting and Compliance provisions below. Capacity Only Option registrations are Full Program Option registrations that do not receive an energy payment for load reductions during a pre-emergency or emergency event.

Actual load reductions of Demand Resource Registrations in Emergency Load Response or Pre-Emergency Load Response Full Program Option or Capacity Only Option used to determine Load Management Event and test capacity compliance for Firm Service Level and Guaranteed Load Drop end-use customers shall be equal to the load reduction provided to the electric distribution company as follows and in accordance with the PJM Manuals:

i) Guaranteed Load Drop compliance will be based on:

   a. the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or there was not a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF. Calculations are represented by:

      Summer: Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

      Non-summer: Minimum of {(comparison load – Load) * LF, (WPL*ZWWAF*LF)-(Load*LF)}

   b. Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

c. Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers include the following:

- ♦ Comparable Day
- ♦ Same Day
- ♦ Customer Baseline
- ♦ Regression Analysis
- ♦ Generation

Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

ii) Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year) - End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

The capacity compliance of Demand Resource Registrations in the Emergency Load Response and Pre-Emergency Load Response Full Program Option, as determined in accordance with these Reporting and Compliance provisions, shall not affect energy payments to such resources for load reductions during an emergency event, as provided in the Market Settlements provisions above and Tariff, Attachment DD.

PJM will submit any required reports to FERC on behalf of the Emergency Load Response and Pre-Emergency Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies pursuant to section 1.5A.3 of PJM's Economic Load Response Program, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies assert prohibit or condition retail participation in PJM's Emergency Load Response and Pre-Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of end-use customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

i. All end-use customers in an aggregation shall be specifically identified;

ii. All end-use customers in an aggregation shall be served by the same electric distribution company ;

iii. All end-use customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statisitical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and

v. Each end-use customer site must meet the requirements for market participation by a Demand Resource.

SCHEDULE 2 -
COMPONENTS OF COST

1. GENERAL COST PROVISIONS

1.1 Permissible Components of Cost-based Offers of Energy.

Each Market Participant obligated to sell energy on the PJM Interchange Energy Market at cost-based rates may include the following components or their equivalent in the determination of costs for energy supplied to or from the PJM Region:

(a) For generating units powered by boilers
Start-Up Costs (including Start Fuel)
Peak-prepared-for maintenance cost

(b) For generating units powered by machines
Start-Up Cost (including Start Fuel)

(c) For all generating units
Incremental maintenance cost
No-load cost during period of operation
Labor cost
Operating costs
Opportunity Costs
Emission allowances/adders
Maintenance Adders
Ten percent adder
Charging costs for Energy Storage Resources
Fuel Cost

1.2 Method of Determining Cost Components.

The PJM Board, upon consideration of the advice and recommendations of the Members Committee, shall from time to time define in detail the method of determining the costs entering into the said components, and the Members shall adhere to such definitions in the preparation of incremental costs used on the Interconnection.

1.3 Application of Cost Components to Three-Part Cost-based Offers.

A cost-based offer, as defined in Operating Agreement, Schedule 1, section 1.2, is a three-part offer consisting of Start-up Costs, No-load Costs, and the Incremental Energy Offer. These terms are as defined in Operating Agreement, section 1.

The following lists the categories of cost that may be applicable to a Market Participant's three-part cost-based offer:

(a) For Start-up Costs
Fuel cost
Emission allowances/adders
Maintenance Adders
Operating costs
Station service

(b) For No-load Costs
Fuel cost
Emission allowances/adders
Maintenance Adders
Operating costs

(c) Incremental Costs in Incremental Energy Offers
Fuel cost
Emission allowances/adders
Maintenance Adders
Operating costs
Opportunity Costs

(d) All fuel costs shall employ the marginal fuel price experienced by the Member.

2. FUEL COST POLICY

2.1 Approved Fuel Cost Policy Requirement for Non-Zero Cost-based Offer.

A Market Seller may only submit a non-zero cost-based offer into the PJM Interchange Energy Market for a generation resource if it has a PJM-approved Fuel Cost Policy, or follows the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, consistent with each fuel type for such generation resource.

2.2 Fuel Cost Policy Approval Process.

(a) A Market Seller shall provide a Fuel Cost Policy to PJM and the Market Monitoring Unit for each generation resource that it intends to submit with a non-zero cost-based offer into the PJM Interchange Energy Market, for each fuel type utilized by the resource. The Market Seller shall submit its initial Fuel Cost Policy for a generation resource to PJM and the Market Monitoring Unit for review and shall update existing Fuel Cost Policies consistent with the requirements set forth below in Operating Agreement, Schedule 2, section 2.6.

(i) For each new generation resource for which the Market Seller intends to submit a non-zero cost-based offer, the Market Seller may also:

A. Submit a provisional Fuel Cost Policy to PJM and the Market Monitoring Unit for review and approval when it does not have commercial operating data. The provisional Fuel Cost Policy shall describe the Market Seller's methodology to procure and price fuel and include all available operating data. Within 90 calendar days of the commercial operation date of such generation resource, the Market Seller shall submit to PJM and the Market Monitoring Unit for review an updated Fuel Cost Policy reflecting actual commercial operating data of the resource; or

B. Follow the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, until PJM approves a new Fuel Cost Policy.

(ii) A Market Seller of a generation resource that is transferred from another Market Seller that intends to submit a non-zero cost-based offer must:

A. Affirm the currently approved Fuel Cost Policy on file for such generation resource prior to the submission of a cost-based offer; or

B. Submit an updated Fuel Cost Policy for review, which must be approved prior to the submission of a cost-based offer developed in accordance with such policy; or

C. Follow the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, until PJM approved a new Fuel Cost Policy.

(b) PJM and the Market Monitoring Unit will have an initial thirty (30) Business Days for review of a submitted policy.

(c) The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve a Market Seller's Fuel Cost Policy.

(d) After it has completed its evaluation of the submitted Fuel Cost Policy, PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the Fuel Cost Policy is approved or rejected. If PJM rejects a Market Seller's Fuel Cost Policy, PJM shall include an explanation for why the Fuel Cost Policy was rejected in its written notification.

(e) PJM shall establish an expiration date for each Fuel Cost Policy, with timely input and advice from the Market Monitoring Unit and Market Seller, and notify the Market Seller of such date at the time of the Fuel Cost Policy approval. Upon such expiration, the Fuel Cost Policy will no longer be deemed approved by PJM and the provisions of Operating Agreement, Schedule 2, section 2.4(b) shall apply.

2.3 Standard of Review.

(a) PJM shall review and approve a Fuel Cost Policy if it meets the requirements set forth in subsections (a)(i) through (vii) of this section. PJM shall reject Fuel Cost Policies that fail to meet such requirements and that do not accurately reflect the applicable costs, such as the fuel source, transportation cost, procurement process used, applicable adders, commodity cost, or provide sufficient information for PJM to verify the Market Seller's fuel cost at the time of the Market Seller's cost-based offer. If PJM rejects a Market Seller's Fuel Cost Policy, PJM shall include an explanation for why the Fuel Cost Policy was rejected in its written notification. A Fuel Cost Policy must:

(i) Provide information sufficient for the verification of the Market Seller's fuel pricing and/or cost estimation method, as further described below and in PJM Manual 15, and how those practices are utilized to determine cost-based offers the Market Seller submits into the PJM Interchange Energy Market;

(ii) Reflect the Market Seller's applicable commodity and/or transportation contracts (to the extent it holds such contracts) and the Market Seller's method of calculating delivered fossil fuel cost, limited to inventoried cost, replacement cost or a combination thereof, that reflect the way fuel is purchased or scheduled for purchase, and set forth all applicable indices as a measure that PJM can use to verify how anticipated spot market purchases are utilized in determining fuel costs;

(iii) Provide a detailed explanation of the basis for and reasonableness of any applicable adders included in determining fuel costs in accordance with PJM Manual 15;

(iv) Account for situations where applicable indices or other objective market measures are not sufficiently liquid by documenting the alternative means actually utilized by the Market Seller to price the applicable fuel used in the determination of its cost-based offers, such as documented quotes for the procurement of natural gas;

(v) Adhere to all requirements of PJM Manual 15 applicable to the generation resource:

(vi) Specify a source for fuel price that can be verified by the Office of the Interconnection or the Market Monitoring Unit after the fact with the same data available to the Market Seller at the time the fuel price estimation was made; and

(vii) Document a standardized method or methods for calculating fuel costs including defining objective triggers for optional fuel cost updates.

(b) To the extent a Market Seller proposes alternative measures to document its fuel costs in its Fuel Cost Policy for a generation resource, the Market Seller shall explain how such alternative measures are consistent with or superior to the standard specified in subsection (a) of this section, accounting for the unique circumstances associated with procurement of fuel to supply the generation resource.

(c) If PJM determines that a Fuel Cost Policy submitted for review does not contain adequate support for PJM to make a determination as to the acceptability of any portion of the proposed policy consistent with the standards set forth above, PJM shall reject the Fuel Cost Policy. If PJM rejects the Fuel Cost Policy, the Market Seller may use:

(i) The existing approved Fuel Cost Policy, if the policy is not expired and is still reflective of the Market Sellers current fuel pricing and/or cost estimation method; or

(ii) The temporary cost offer methodology provided in Operating Agreement, Schedule 2, section 6.3 to develop its cost-based offers until such time as PJM approves a new Fuel Cost Policy for the Market Seller.

2.4 Expiration of Approved Fuel Cost Policies.

(a) PJM, in consultation with the Market Seller and with timely input and advice from the Market Monitoring Unit, may:

(i) Update the Market Seller's Fuel Cost Policy expiration date, with at least 90 days notification to the Market Seller, due to a business rule change in the PJM Governing Documents.

(ii) Immediately expire the Market Seller's Fuel Cost Policy with written notification to the Market Seller when a change in circumstance causes the Market Seller's fuel pricing and/or cost estimation method to be no longer consistent with the approved Fuel Cost Policy, this Operating Agreement, Schedule 2 or PJM Manual 15.

(b) If the Market Seller of a generation resource that has been transferred from another Market Seller does not affirm the current approved Fuel Cost Policy on file for that generation resource, then such Fuel Cost Policy shall terminate as of the date on which the generation resource was transferred to the new Market Seller.

(c) PJM shall notify the Market Seller and the Market Monitoring Unit in writing when it has approved or denied a requested update to a Fuel Cost Policy expiration date and the rationale for its determination.

(d) On the next Business Day following the expiration of a Fuel Cost Policy, the Market Seller may only submit a cost-based offer of zero or a cost-based offer that is consistent with the temporary cost offer methodology in Operating Agreement, Schedule 2, section 6.3 until a new Fuel Cost Policy is approved by PJM for the relevant resource. If PJM expires a Market Seller's previously approved Fuel Cost Policy under Operating Agreement, Schedule 2, section 2.4(a)(i) or (ii), PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, and include an explanation for the expiration, along with relevant documentation to support the expiration of a Fuel Cost Policy. Upon expiration, the Market Seller may rebut the expiration pursuant to Operating Agreement, Schedule 2, section 6.2

2.5 Information Required To Be Included In Fuel Cost Policies.

(a) Each Market Seller shall include in its Fuel Cost Policy the following information, as further described in the applicable provisions of PJM Manual 15:

(i) For all Fuel Cost Policies, regardless of fuel type, the Market Seller shall provide a detailed explanation of the Market Seller's established method of calculating or estimating fuel costs, indicating whether fuel purchases are subject to a contract price and/or spot pricing, and specifying how it is determined which of the contract prices and/or spot market prices to use. The Market Seller shall include its method for determining commodity, handling and transportation costs.

(ii) For Fuel Cost Policies applicable to generation resources using a fuel source other than natural gas, the Market Seller shall adhere to the following guidelines:

1. Fuel costs for solar and run-of-river hydro resources shall be zero.

2. Fuel costs for nuclear resources shall not include in-service interest charges whether related to fuel that is leased or capitalized.

3. For Pumped Storage Hydro resources, fuel cost shall be determined based on the amount of energy necessary to pump from the lower reservoir to the upper reservoir.

4. For all resources receiving renewable energy credits and/or production tax credits that plan to submit a non-zero cost based offer into the energy market, the Market Seller shall identify how it accounts for renewable energy credits and production tax credits.

5. For solid waste, bio-mass and landfill gas resources, the Market Seller shall include the costs of such fuels even when the cost is negative.

6. For Energy Storage Resources, fuel cost shall include costs to charge for later injection to the grid.

(iii) Market Sellers shall report, for all of the generation resource's operating modes, fuels, and at various operating temperatures, the incremental, no load and start heat requirements, the method of developing heat inputs, and the frequency of updating heat inputs when requested by the Office of the Interconnection.

(iv) Market Sellers shall include any applicable unit specific performance factors, and the method used to determine them, which may be modified seasonally to reflect ambient conditions when requested by the Office of the Interconnection.

(v) Market Sellers shall include the cost-based Start-Up Cost calculation for the generation resource, and identify for each temperature state the starting fuel (MMBtu), station service (MWh), and start Maintenance Adder, when requested by the Office of the Interconnection.

(vi) A Fuel Cost Policy shall also include any other incremental operating costs included in a Market Seller's cost-based offer for a resource, including but not limited to the consumables used for operation and the marginal value of costs in terms of dollars per MWh or dollars per unit of fuel, along with all applicable descriptions, calculation methodologies associated with such costs, and frequency of updating such costs.

2.6 Periodic Update and Review of Fuel Cost Policies.

Prior to expiration of a Fuel Cost Policy, all Market Sellers will be required to either submit to PJM and the Market Monitoring Unit an updated Fuel Cost Policy that complies with this Operating Agreement, Schedule 2 and PJM Manual 15, or confirm that their expiring Fuel Cost Policy remains compliant, pursuant to the procedures and deadlines specified in PJM Manual 15. PJM shall consult with the Market Monitoring Unit, and consider any input timely received from the Market Monitoring Unit, in its determination of whether to approve a Market Seller's updated Fuel Cost Policy. After it has completed its evaluation of the request, PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of its determination whether the updated Fuel Cost Policy is approved or rejected. If PJM rejects a Market Seller's updated Fuel Cost Policy, in its written notification, PJM shall provide an explanation for why the Fuel Cost Policy was rejected.

The Market Seller shall follow the applicable processes and deadlines specified in this Operating Agreement, Schedule 2 and the PJM Manual 15 to submit an updated Fuel Cost Policy:

(a) If the Market Seller's fuel pricing or cost estimation method is no longer consistent with the approved Fuel Cost Policy, or

(b) If a Market Seller desires to update its Fuel Cost Policy.

2.7 Market Monitoring Unit Review For Market Power Concerns.

Nothing in this Operating Agreement, Schedule 2 is intended to abrogate or in any way alter the responsibility of the Market Monitoring Unit to make determinations about market power pursuant to Tariff, Attachment M and Attachment M-Appendix.

3. EMISSION ALLOWANCES/ADDERS

3.1 Review of Emissions Allowances/Adders.

(a) For emissions costs, Market Sellers shall specify the emissions rate of each generation resource, the method for determining the emissions allowance cost, and the frequency of updating emission rates in the resource's Fuel Cost Policy. Emissions rates must be submitted to PJM and the Market Monitoring Unit. Emissions rates must be updated when they are no longer accurate. PJM shall establish an expiration date for emissions rates, with timely input and advice from the Market Monitoring Unit and Market Seller, and notify the Market Seller of such date at the time of the emissions rate approval. Market Sellers must submit updated rates prior to the expiration of the current adder. The Market Seller of a generation resource with an expired emission rate, or otherwise does not have an approved emission rate, may not include an emission adder in the cost-based offer associated with such generation resource.

(b) Market Sellers may submit emissions cost information to PJM and the Market Monitoring Unit as part of the information it submits during the annual Fuel Cost Policy review process, described in Operating Agreement, Schedule 2, section 2.6. The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix, section II.A.2. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve emissions costs.

4. MAINTENANCE ADDERS & OPERATING COSTS

4.1 Maintenance Adders.

Maintenance Adders are expenses directly related to electric production and can be a function of starts and/or run hours. Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses. Maintenance Adders are calculated as the 10 or 20 year average cost of a unit's maintenance history, or all available actual maintenance history if a unit has less than 20 years of maintenance history. Maintenance Adders are comprised of major maintenance and minor maintenance. Market Sellers that wish to include major maintenance and/or unit specific minor maintenance in the Maintenance Adder shall submit and receive approval of the requested adder from the Office of Interconnection, prior to the inclusion of such adder (or prior to the expiration of a previously approved adder) in cost-based offers. Notwithstanding, Market Sellers may utilize the default minor maintenance adder provided in this Operating Agreement, Schedule 2, section 4.5 in lieu of submitting unit-specific minor maintenance adder. The major inspection and overhaul costs listed below in sections (a)-(c) are not exhaustive. A Market Seller may include costs in cost-based offers if those costs are similar to the costs outlined in this provision, so long as they are variable costs that are directly attributable to the production of electricity.

(a) Major maintenance are overhauls, repairs, or refurbishments that require disassembly to complete of boiler, reactor, heat recovery steam generator, steam turbine, gas turbine, hydro turbine, generator, or engine. Major maintenance includes, but is not limited to, the following costs:

- turbine blade repair/replacement;
- turbine diaphragm repair;
- turbine casing repair/replacement;
- turbine bearing repair/refurbishment;
- turbine seal repair/replacement and generator refurbishment;
- selective catalytic reduction and carbon monoxide reduction catalyst replacement;

- compressor blade repair/replacement;
- hot gas path inspections, repairs, or replacements;
- steam stop valve repairs;

- steam throttle valve repairs;
- steam nozzle block repairs;
- steam intercept valve repairs;
- generator stator or rotor rewind, refurbishment, or replacement;
- scrubber refurbishment;
- water wall panel replacement;
- pendant or super heater replacement;
- economizer replacement;
- diesel/reciprocating engine overhaul;
- reactor refueling;
- steam generator overhaul/replacement.

(b) Minor maintenance are repairs or refurbishments on equipment and components directly related to electric production and not otherwise classified as major maintenance, such as main steam, feed water, condensate, condenser, cooling towers, transformers, gas turbine inlet air and exhaust, and fuel systems. Minor maintenance include, but are not limited to, the following costs associated with the aforementioned systems:

- heat transfer replacement and cleaning;
- cooling tower fan motor and gearbox inspection;
- cooling tower fill and drift eliminators replacement;
- air filter replacement;
- repair and replacement of valves and piping components, control equipment, pumps, motors, condenser components, transformers, cabling, breakers, motor control centers, switch gear, fuel and ash handling, selective catalytic reduction and scrubber emission control equipment and components, mills burners, boiler components, fan components, reactor recirculation components, hydraulic control rod drive system components and reactor components.

(c) Maintenance costs that cannot be included in a Market Seller's cost-based offer are preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment.

4.2 Operating Costs.

(a) Operating costs are expenses related to consumable materials used during unit operation and include, but are not limited to, lubricants, chemicals, limestone, trona, ammonia, acids, caustics, water injection, activated carbon for mercury control, and demineralizers usage. These operating costs not exhaustive. A Market Seller may include other operating costs in cost-based offers so long as they are operating costs that are directly attributable to the production of energy.

(b) Operating costs may be calculated based on a fixed or rolling average of values from one to five years in length, reviewed (and updated if changed) annually, or a rolling average from twelve to sixty months in length, reviewed (and updated if changed) monthly.

(c) Market Sellers that wish to include unit-specific operating costs adder shall submit and receive approval of the requested unit-specific fixed average adder or the most recent month rolling average adder from the Office of Interconnection prior to the inclusion of such adder (or prior to the expiration of a previously approved adder) in cost-based offers. Notwithstanding, Market Sellers may utilize the default operating costs adder provided in this Operating Agreement, Schedule 2, section 4.5 in lieu of submitting unit-specific operating costs adder.

4.3 Labor Costs.

Labor costs included in cost-based offers do not include straight-time labor costs and are limited to contractor labor or plant personnel overtime labor included in the Maintenance Adder associated with maintenance activities directly related to electric production. Straight time labor expenses may be included under an Avoidable Cost Rate in the RPM auction.

4.4 Review of Maintenance Adders & Operating Costs.

(a) Maintenance Adders and operating costs may be submitted and reviewed annually by the Office of Interconnection and the Market Monitor Unit, if the Market Seller does not use the default adders described in Operating Agreement, Schedule 2, section 4.5. The Market Seller must submit Maintenance Adders if they are no longer accurate due to major maintenance rolling off the cost history. Maintenance Adders and operating costs cannot include any costs that are included in the generation resource's Avoidable Cost Rate pursuant to Tariff, Attachment DD, section 6.8(c).

(b) Market Sellers must specify the maintenance history years utilized in calculating Maintenance Adders during the review.

(c) Market Sellers must specify the years used to calculate Operating Costs during the review. Market Sellers that elect to use a twelve month to sixty month rolling average must submit these costs for a monthly review.

(d) The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix, section II.A.2. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve Maintenance Adders and operating costs.

(e) PJM shall establish an expiration date for each Maintenance Adder and operating costs, and notify the Market Seller of such date at the time of the Maintenance Adders and operating costs approval.

4.5 Default Adder.

A Market Seller may elect to utilize a default minor maintenance adder or submit unit-specific minor maintenance costs to the Office of Interconnection and the Market Monitoring Unit. All major maintenance costs on a unit-specific basis must be submitted to the Office of Interconnection and the Market Monitoring Unit.

A Market Seller may include a default operating costs adder in the cost-based energy offer in lieu of submitting unit-specific operating costs for review and approval.

The default adders are as follows:

Technology Type	Default Minor Maintenance Adders ($/MWh)	Default Operating Costs Adders ($/MWh)
Combined Cycle	0.98	0.40
Combustion Turbine	3.59	0.75
Reciprocating Engine	4.03	1.62
Fossil Steam	1.71	2.87

The default adders shown above shall be escalated annually utilizing the Handy-Whitman Index and shall be posted annually by the Office of Interconnection. The default adders may not be utilized by a Market Seller prior to the expiration of a unit-specific maintenance adder or operating costs adder previously approved by the Office of Interconnection.

5. OPPORTUNITY COSTS

(a) For a generating unit that is subject to operational limitations due to energy or environmental limitations imposed on the generating unit by Applicable Laws and Regulations, the Market Participant may include a calculation of its "Opportunity Costs" which is an amount reflecting the unit-specific Energy Market Opportunity Costs expected to be incurred. Such unit-specific Energy Market Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the relevant compliance period, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Energy Market Opportunity Cost shall be zero. Notwithstanding the foregoing, a Market Participant may submit a request to PJM for consideration and approval of an alternative method of calculating its Energy Market Opportunity Cost if the standard methodology described herein does not accurately represent the Market Participant's Energy Market Opportunity Cost.

(b) For a generating unit that is subject to operational limitations because it only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, or (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure, the Market Participant may include a calculation of its "Opportunity Costs" which is an amount reflecting the unit-specific Non-Regulatory Opportunity Costs expected to be incurred. Such unit-specific Non-Regulatory Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the period of time in which the unit is bound by the referenced restrictions, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Non-Regulatory Opportunity Cost shall be zero.

6. PENALTY PROVISIONS

6.1 Penalties.

(a) If upon review of a Market Seller's cost-based offer, PJM determines that the offer is not in compliance with the Market Seller's PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2 and the Market Monitoring Unit agrees with that determination, or the Market Monitoring Unit determines that the offer is not in compliance with the Market Seller's PJM-approved Fuel Cost Policy and PJM agrees with the Market Monitoring Unit's determination, or PJM determines that any portion of the cost-based offer is not in compliance with this Operating Agreement, Schedule 2, the Market Seller shall be subject to a penalty. If:

1. The Market Seller ceased submitting the non-compliant offer either prior to, or upon notification from PJM, or the Market Seller reports such error to PJM after ceasing submission of the non-compliant cost-based offer then the penalty calculation will use the average hourly MWh and LMP for each hour of the day across the non-compliant period, as shown in the equation below. For the purposes of this equation, the non-compliant period is defined as the first hour of the Operating Day for which the non-compliant offer was first submitted through the earlier of: a) the last hour of the Operating Day for which the non-compliant offer was submitted (inclusive of all hours, even where the offer was correct, in between the same non-compliant offer); or b) notification of the non-compliant offer from PJM (inclusive of all hours, even where the offer was correct, in between the same non-compliant offer).

$$\text{Non-Escalating Penalty} = \sum_{h=1}^{24} \left(\left(\frac{1}{20} \right) \text{ x } LMP_h \text{ x } MW_h \text{ x E x I} \right)$$

where:

$_h$ is the applicable hour of the Operating Day.

LMP_h is the average hourly real-time LMP at the applicable location of the resource for the given hour across the non-compliant period.

MW_h is the average hourly available capacity of the resource for the given hour across the non-compliant period, where available capacity is defined as the greater of the real-time megawatt output and emergency maximum of the generation resource.

E is the Market Seller error identification factor. The Market Seller error identification factor shall be equal 0.25 when the non-compliant offer is identified by the Market Seller without inquiry from or being prompted by PJM or the Market Monitoring Unit, and PJM, with timely input and advice from the Market Monitoring Unit, agrees that the Market Seller first identified the error. The Market Seller error identification shall equal 1 in the absence of a valid self-identified error.

I is the market impact factor over the duration of the non-compliant cost-based offer. The market impact factor shall be equal to 1 if the Market Seller continued submitting non-compliant offers after receiving notice from PJM of its non-compliant offer, or if the Market Seller continued submitting non-compliant offers after notifying PJM of the non-compliant cost-based offer, or when any of the following conditions exist for any hour throughout the duration of the non-compliant cost-based offer:

A. The generation resource clears in the Day-ahead Energy Market on the non-compliant cost-based offer, or runs in Real-time Energy Market on the non-compliant cost-based offer and is either:

(i) paid day-ahead or balancing operating reserves as described in Operating Agreement, Schedule 1, section 3.2.3; or

(ii) The marginal resource for energy, transmission constraint control, regulation or reserves.

B. The Market Seller does not pass the three pivotal supplier test as described in Operating Agreement, Schedule 1, section 6.4.1(e) and any of the following conditions apply:

(i) The generation resource is not committed

(ii) The generation resource runs on its cost-based offer

(iii) The generation resource is running on its market-based offer and it did not pass the three pivotal supplier test at the time of commitment

C. The non-compliant incremental cost-based offer is greater than $1,000.MWh

If none of the above conditions apply, then the market impact factor shall be equal to 0.1

2. In addition to being issued the penalty described in 6.1(a)(1), a Market Seller will be subject to a daily escalating penalty for each day beyond which the Market Seller continues submitting the non-compliant cost-based offer after notification from PJM, or after the Market Seller reports such error to PJM. Escalating daily penalty will be calculated as shown in the equation below:

$$\text{Escalating Daily Penalty} = \sum_{h=1}^{24} \left(\left(\frac{d}{20} \right) \text{x } LMP_h \text{ x } MW_h \right)$$

where:

d is the the number of days, starting at 2 and increasing by 1 for each additional day of non-compliance following notification, and capped at a value of 15.

$_h$ is the applicable hour of the Operating Day.

LMP_h is the hourly real-time LMP at the applicable pricing location for the resource for the applicable hour of the Operating Day.

MW_h is the hourly available capacity of the resource for the applicable hour of the Operating Day, where available capacity is defined as the greater of the real-time megawatt output and emergency maximum of the generation resource.

(b) All charges collected pursuant to this provision shall be allocated to Market Participants based on each Market Participant’s real-time load ratio share for each applicable hour, as determined based on the Market Participant’s total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region.

(c) Market Sellers that are assessed a penalty for a cost-based offer not in compliance with the Market Seller’s PJM-approved Fuel Cost Policy, the temporary cost offer methodology, or this Schedule 2 shall be assessed penalties until the day after PJM determines that the Market Seller’s cost-based offers are in compliance with the Market Seller’s approved Fuel Cost Policy or in compliance with this Schedule 2. Such penalties will be assessed for no less than one (1) Operating Day.

6.2 Rebuttal Period To Challenge Expiration of Fuel Cost Policy.

Market Sellers who have a Fuel Cost Policy that has been immediately expired by PJM will be provided a three (3) Business Day rebuttal period, starting from the date of expiration, to submit supporting documentation to PJM demonstrating that the expired Fuel Cost Policy accurately reflects the fuel pricing and/or cost estimation method documented in the previously approved Fuel Cost Policy that was expired. However, if, upon review of the Market Seller's supporting documentation, PJM determines that the expired policy accurately reflects the Market Seller's actual methodology used to develop the cost-based offer that was submitted at the time of expiration and that the Market Seller has not violated its Fuel Cost Policy, then PJM will make whole the Market Seller via uplift payments for the time period for which the applicable Fuel Cost Policy had been expired and the generation resource was mitigated to its cost-based offer.

6.3 Exemption From Penalty

(a) A Market Seller will not be subject to a penalty under Operating Agreement, Schedule 2, section 6.1 for utilizing a fuel pricing and/or cost estimation method inconsistent with the methodology in the Market Seller's PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2 if the reason for fuel pricing and/or cost estimation deviation is due to an unforeseen event outside of the control of the Market Seller, its agents, and its affiliated fuel suppliers which, by exercise of due diligence the Market Seller could not reasonably have contemplated at the time the Fuel Cost Policy was developed, such as:

(i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe;

(ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe or other fuel delivery infrastructure;

(iii) interruption and/or curtailment of firm transportation and/or storage by transporters;

(iv) acts of unaffiliated third parties including but not limited to strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and

(v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction.

(b) Market Seller shall provide evidence of the event and direct impact on the Market Seller's ability to utilize a fuel pricing and/or cost estimation method consistent with the methodology in the Market Seller's PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2. Such evidence shall be provided to PJM and the Market Monitoring Unit. Upon providing such evidence to PJM and the Market Monitoring Unit, and after receiving timely comments from the Market Monitoring Unit, PJM shall determine and notify the Market Seller as to whether the evidence sufficiently demonstrates that the force majeure event directly impacted the Market

Seller’s ability to conform to the methodology described in the applicable PJM-approved Fuel Cost Policy. The applicability of this provision shall not apply for economic hardship nor obviate the requirement for a Market Seller to submit cost-based offers that are just and reasonable, and utilize best available information to develop fuel costs during a force majeure event.

6.4 Temporary Cost Offer Methodology

(a) As an option, Market Sellers may utilize the temporary cost offer methodology to calculate a generation resource’s cost-based offer while developing a new Fuel Cost Policy in good faith for the following:

(i) Generation resources that initiate participation in the PJM Energy Market

(ii) Generation resources transferring from one Market Seller to another Market Seller

(iii) Generation resources that have an expired Fuel Cost Policy

(b) The temporary cost offer methodology shall be comprised of the index settle price, described below, at the PJM-assigned commodity pricing point multiplied by heat input curves submitted by the Market Seller, as described in Manual 15.

For generation resources that opt-out of intraday offers, the last published closing index settle price shall be used for all hours of the Operating Day.

For generation resources that opt-in to intraday offers, index settle prices shall be based on the last published closing settle price for all hours of the Operating Day , and updated to reflect the:

1. last published closing settle price, if decreased, for hours ending 11 through 24 for natural gas

2. last published closing settle price, if decreased, for all hours of the Operating Day for all other fuel types

(c) The commodity pricing point and index publication source shall be assigned by PJM in consultation with the Market Seller and with timely input and advice from the Market Monitoring Unit.

(d) A Market Seller may not include any of the other permissible components for cost-based offers that listed in this Operating Agreement, section 1.1.

(e) If a Market Seller without a PJM-approved Fuel Cost Policy does not utilize this temporary cost offer methodology to calculate its cost-based offer, the Market Seller shall only submit a zero cost-based offer.

SCHEDULE 2 - EXHIBIT A - EXPLANATION OF THE TREATMENT OF THE COSTS OF EMISSION ALLOWANCES

The cost of emission allowances is included in "Other Incremental Operating Costs" pursuant to Schedule 2. The replacement cost of emission allowances will be used to recover the cost of emission allowances consumed as a result of producing energy for the PJM Region.

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Consistent with definitions promulgated by the PJM Board upon consideration of the advice and recommendations of the Members Committee under Schedule 2, each Member subject to Schedule 2 will determine and provide to the Interconnection its replacement cost of emission allowances, such cost to be an amount not exceeding the market price index published by Cantor-Fitzgerald Environmental Brokerage Services ("EBS"), or a PJM Board approved index in the event that EBS should cease publication of such index. As with all other components of cost required for accounting under this Agreement, each Member subject to Schedule 2 will use the same replacement cost of emissions allowances, so determined, as it uses for coordinating operation of its generating facilities hereunder.

For each Member subject to Schedule 2, the cost of emissions allowances is included in the cost of energy supplied to or received from the PJM Region.

Payment

The Members subject to Schedule 2 waive the right of payment-in-kind for emission allowances for transactions wholly between the parties. Cash payments for emission allowances consumed in providing energy for the PJM Region shall be incorporated into and conducted pursuant to the billing procedures for energy prescribed by this Agreement.

Calculation of Emission Allowance Amount and Cost

Pursuant to the letter from the PJM Interconnection to FERC dated June 26, 1995, the calculation of an annual average for the cost of emission allowances, described below, is required due to the profile of the PJM physical system and PJM Energy Management software system. An average emission allowance cost based on a standard production cost study case will be used to calculate the average cost of emission allowances for each pool megawatt produced.

The Emission Allowances (Tons of SO2) associated with a transaction will be calculated by multiplying the magnitude of a transaction (MWhr) by an Emissions per MWHr Factor (Tons of SO2 per MWhr):

Emission Allowances Used	=	Transaction Magnitude	x	Emissions per MWhr Factor
(Tons of S02)		(MWhr)		(Tons of S02 per MWhr)

The Emissions per MWHr Factor will be calculated by dividing the forecast annual emissions from all Phase I units (Tons of SO2) by the Forecast Annual Total PJM Energy Production (MWhr):

$$\text{Emissions per MWhr Factor (Tons of SO2 per MWhr)} = \frac{\text{Forecast Annual Phase I Unit Emissions (Tons of SO2)}}{\text{Forecast Annual Total PJM Energy Production (MWhr)}}$$

Likewise, the cost (Dollars) of the Emission Allowances for a transaction will be calculated by multiplying the transaction magnitude (MWhr) by a Charge per MWhr Factor (Dollars per MWHr).

$$\text{Cost of Emission Allowances Used (Dollars)} = \text{Transaction Magnitude (MWhr)} \times \text{Charge per MWhr Factor (Dollars per MWhr)}$$

The Charge per MWhr Factor will be calculated by multiplying, for each Member subject to Schedule 2, its Forecast Annual Emissions (Tons of SO2)by its respective Emissions Allowance Replacement Cost (Dollars per Ton of SO2) to yield each the forecasted annual cost of emissions (Dollars). Then, the total of forecasted annual cost of emissions for each Member subject to Schedule 2 is divided by the Forecast Annual Total PJM Energy Production (MWhr) to determine the Charge per MWHr Factor (Dollars per MWHr).

$$\text{Charge per MWhr Factor} = \frac{\Sigma(A \times B)}{C}, \text{ where:}$$

A = Member's Forecasted Annual Emissions, (Tons of SO2)
B = Emission Allowance Replacement Cost, (Dollars per Ton of SO2, per company)
C = Forecast Annual PJM Energy Production, (MWhr)

SCHEDULE 3 - ALLOCATION OF THE COST AND EXPENSES OF THE OFFICE OF THE INTERCONNECTION

(a) Each group of Affiliates, each group of Related Parties, and each Member that is not in such a group shall pay an annual membership fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee as of the Effective Date shall be $5,000. The annual membership fee shall be charged on a calendar year basis. In the year that a new membership commences, the annual membership fee may be reduced, at the election of the entity joining, by 1/12th for each full month that has passed prior to membership commencing. If the entity seeking to join elects to pay a prorated annual membership fee as provided here, it shall not be permitted to vote at meetings until the first day following the date that its entry as a new Member is announced at a Members Committee meeting, provided that if an entity's membership is terminated and it seeks to rejoin within twelve months, it will be subject to the full $5,000 annual membership fee. Annual membership fees shall not be refunded, in whole or in part, upon termination of membership. Each group of Affiliates, each group of Related Parties, and each Member that does not timely pay its annual membership fee by January 1 shall be deemed to have given notice of its intent to withdrawal from PJM Membership in accordance with Operating Agreement, section 18.18.2. PJM shall provide the affected group of Affiliates, group of Related Parties and/or Member with notification (electronic or otherwise) of its intent to apply this provision and the affected group of Affiliates, group of Related Parties and/or Member shall have 90 days therefrom to make payment of its annual membership fee before its withdrawal from PJM Membership becomes effective.

(b) Each group of State Offices of Consumer Advocates from the same state or the District of Columbia and each State Consumer Advocate that nominates its representative to vote on the Members Committee but is not in such a group shall pay an annual fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee shall be $500. The annual membership fee shall be charged on a calendar year basis and shall not be subject to proration for memberships commencing during a calendar year.

(c) The amount of the annual fees provided for herein shall be adjusted from time to time by the PJM Board to keep pace with inflation.

(d) All remaining costs of the operation of the LLC and the Office of the Interconnection and the expenses, including, without limitation, the costs of any insurance and any claims not covered by insurance, associated therewith as provided in this Agreement shall be costs of PJM Interconnection, L.L.C. Administrative Services and shall be recovered as set forth in Tariff, Schedule 9. Such costs may include costs associated with debt service, including the costs of funding reserve accounts or meeting coverage or similar requirements that financing covenants may necessitate.

(e) An entity accepted for membership in the LLC shall pay all costs and expenses associated with additions and modifications to its own metering, communication, computer, and other appropriate facilities and procedures needed to effect the inclusion of the entity in the operation of the Interconnection, and for additional services requested by Members from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection.

SCHEDULE 4 -
STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE LLC

Any entity which wishes to become a Member of the LLC shall, pursuant to Section 11.6 of this Agreement, tender to the President an application, upon the acceptance of which it shall execute a supplement to this Agreement in the following form:

Additional Member Agreement

1. This Additional Member Agreement (the "Supplemental Agreement"), dated as of ___________________, is entered into among ______________ and the President of the LLC acting on behalf of its Members.

2. ______________ has demonstrated that it meets all of the qualifications required of a Member to the Operating Agreement. If expansion of the PJM Region is required to integrate _____________________'s facilities, a copy of Attachment J from the PJM Tariff marked to show changes in the PJM Region boundaries is attached hereto. _____________________ agrees to pay for all required metering, telemetering and hardware and software appropriate for it to become a member.

3. _______________________ agrees to be bound by and accepts all the terms of the Operating Agreement as of the above date.

4. _______________________ hereby gives notice that the name and address of its initial representative to the Members Committee under the Operating Agreement shall be:
____

5. The President of the LLC is authorized under the Operating Agreement to execute this Supplemental Agreement on behalf of the Members.

6. The Operating Agreement is hereby amended to include ___________ as a Member of the LLC thereto, effective as of ___________________, _____, the date the President of the LLC countersigned this Agreement.

IN WITNESS WHEREOF, ________________________ and the Members of the LLC have caused this Supplemental Agreement to be executed by their duly authorized representatives.

Members of the LLC

By: ________________________________
Name: ________________________________
Title: President

By: ________________________________
Name: ________________________________
Title: ________________________________

SCHEDULE 5 -
PJM DISPUTE RESOLUTION PROCEDURES

References to section numbers in this Schedule 5 refer to sections of this Schedule 5, unless otherwise specified.

1. DEFINITIONS

1.1 Alternate Dispute Resolution Coordinator.

"Alternate Dispute Resolution Coordinator" shall mean the individual designated by the Office of the Interconnection.

1.2 Related PJM Agreements.

"Related PJM Agreements" shall mean this Agreement, the Consolidated Transmission Owners Agreement and the Reliability Assurance Agreement.

2. PURPOSES AND OBJECTIVES

2.1 Common and Uniform Procedures.

The PJM Dispute Resolution Procedures are intended to establish common and uniform procedures for resolving disputes arising under the Related PJM Agreements. To the extent any of the foregoing agreements or the PJM Tariff contains dispute resolution provisions expressly applicable to disputes arising thereunder, however, this Agreement shall not supplant such provisions, which shall apply according to their terms.

2.2 Interpretation.

To the extent permitted by applicable law, the PJM Dispute Resolution Procedures are to be interpreted to effectuate the objectives set forth in Operating Agreement, section 2.1. To the extent permitted by these PJM Dispute Resolution Procedures, the Alternate Dispute Resolution Coordinator shall coordinate with the established dispute resolution committee of an Applicable Regional Entity, where appropriate, in order to conserve administrative resources and to avoid duplication of dispute resolution staffing.

3. NEGOTIATION AND MEDIATION

3.1 When Required.

The parties to a dispute shall undertake good-faith negotiations to resolve any dispute as to a matter governed by one of the Related PJM Agreements. Each party to a dispute shall designate an executive with authority to resolve the matter in dispute to participate in such negotiations. Any dispute as to a matter governed by one of the Related PJM Agreements that has not been resolved through good-faith negotiation shall be subject to non-binding mediation prior to the initiation of arbitral, regulatory, judicial, or other dispute resolution proceedings as may be appropriate as provided by these PJM Dispute Resolution Procedures.

3.2 Procedures.

3.2.1 Initiation.

If a dispute that is subject to the mediation procedures specified herein has not been resolved through good-faith negotiation, a party to the dispute shall notify the Alternate Dispute Resolution Coordinator in writing of the existence and nature of the dispute prior to commencing any other form of proceeding for resolution of the dispute. The Alternate Dispute Resolution Coordinator shall have ten calendar days from the date it first receives notification of the existence of a dispute from any of the parties to the dispute in which to distribute to the parties a list of mediators.

3.2.2 Selection of Mediator.

The Alternate Dispute Resolution Coordinator shall distribute to the parties by facsimile or other electronic means a list containing the names of seven mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as it shall deem appropriate to the dispute. The Alternate Dispute Resolution Coordinator may draw from the lists of mediators maintained by the established dispute resolution committee of an Applicable Regional Entity, as the Alternate Dispute Resolution Coordinator shall deem appropriate. In the event the Office of the Interconnection is one of the parties to the dispute, the Alternate Dispute Resolution Coordinator shall distribute the names of all qualified mediators on the Alternate Dispute Resolution Coordinator's list. The persons on the proposed list of mediators shall have no official, financial, or personal conflict of interest with respect to the issues in controversy, unless the interest is fully disclosed in writing to all participants in the mediation process and all such participants waive in writing any objection to the interest. The parties shall then alternate in striking names from the list with the last name on the list becoming the mediator. The determination of which party shall have the first strike off the list shall be determined by lot. The parties shall have ten calendar days to complete the mediator selection process, unless the time is extended by mutual agreement.

3.2.3 Advisory Mediator.

If the Alternate Dispute Resolution Coordinator deems it appropriate, it shall distribute two lists, one containing the names of seven mediators with mediation experience (or a list containing the names of all current mediators in the event of a dispute involving the Office of the Interconnection), and one containing the names of seven mediators with technical or business experience in the electric power industry. In connection with circulating the foregoing lists, the Alternate Dispute Resolution Coordinator shall specify one of the lists as containing the proposed mediators, and the other as a list of proposed advisors to assist the mediator in resolving the dispute. The parties shall then utilize the alternative strike procedure set forth above until one name remains on each list, with the last named persons serving as the mediator and advisor.

3.2.4 Mediation Process.

The disputing parties shall attempt in good faith to resolve their dispute in accordance with procedures and a timetable established by the mediator. In furtherance of the mediation efforts, the mediator may:

(a) Require the parties to meet for face-to-face discussions, with or without the mediator;

(b) Act as an intermediary between the disputing parties;

(c) Require the disputing parties to submit written statements of issues and positions;

(d) If requested by the disputing parties at any time in the mediation process, provide a written recommendation on resolution of the dispute including, if requested, the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties; and

(e) Adopt, when appropriate, the Center for Public Resources Model ADR Procedures for the Meditation of Business Disputes (as revised from time to time) to the extent such Procedures are not inconsistent with any rule, standard, or procedure adopted by the Office of the Interconnection or with any provision of this Agreement.

3.2.5 Mediator’s Assessment.

(a) If a resolution of the dispute is not reached by the thirtieth day after the appointment of the mediator or such later date as may be agreed to by the parties, if not previously requested to do so the mediator shall promptly provide the disputing parties with a written, confidential, non-binding recommendation on resolution of the dispute, including the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties. The recommendation may incorporate or append, if and as the mediator may deem appropriate, any recommendations or any assessment of the positions of the parties by the advisor, if any. Upon request, the mediator shall provide any additional recommendations or assessments the mediator shall deem appropriate.

(b) At a time and place specified by the mediator after delivery of the foregoing recommendation, the disputing parties shall meet in a good faith attempt to resolve the dispute in light of the recommendation of the mediator. Each disputing party shall be represented at the meeting by a person with authority to settle the dispute, along with such other persons as each disputing party shall deem appropriate. If the disputing parties are unable to resolve the dispute at or in connection with this meeting, then: (i) any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate as provided in the PJM Dispute Resolution Procedures; and (ii) the recommendation of the mediator, and any statements made by any party in the mediation process, shall have no further force or effect, and shall not be admissible for any purpose, in any subsequent arbitral, administrative, judicial, or other proceeding.

3.3 Costs.

Except as specified in Section 4.13, the costs of the time, expenses, and other charges of the mediator and any advisor, and of the mediation process, shall be borne by the parties to the dispute, with each side in a mediated matter bearing one-half of such costs, and each party bearing its own costs and attorney's fees incurred in connection with the mediation.

4. ARBITRATION

4.1 When Required.

Any dispute as to a matter: (i) governed by one of the Related PJM Agreements that has not been resolved through the mediation procedures specified herein, (ii) involving a claim that one or more of the parties owes or is owed a sum of money, and (iii) the amount in controversy is less than $1,000,000.00, shall be subject to binding arbitration in accordance with the procedures specified herein. If the parties so agree, any other disputes as to a matter governed by a Related PJM Agreement may be submitted to binding arbitration in accordance with the procedures specified herein.

4.2 Binding Decision.

Except as specified in Operating Agreement, Schedule 5, section 4.1, the resolution by arbitration of any dispute under this Agreement shall not be binding.

4.3 Initiation.

A party or parties to a dispute which is subject to the arbitration procedures specified herein shall send a written demand for arbitration to the Alternate Dispute Resolution Coordinator with a copy to the other party or parties to the dispute. The demand for arbitration shall state each claim for which arbitration is being demanded, the relief being sought, a brief summary of the grounds for such relief and the basis for the claim, and shall identify all other parties to the dispute.

4.4 Selection of Arbitrator(s).

The parties to a dispute for which arbitration has been demanded may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of arbitrators prepared for the dispute by the Alternate Dispute Resolution Coordinator and delivered to the parties by facsimile or other electronic means promptly after receipt by the Alternate Dispute Resolution Coordinator of a demand for arbitration. The Alternate Dispute Resolution Coordinator may draw from the lists of arbitrators maintained by the established dispute resolution committee of an Applicable Regional Entity, as the Alternate Dispute Resolution Coordinator deems appropriate. In the event the Office of the Interconnection is one of the parties to the dispute, the Alternate Dispute Resolution Coordinator shall distribute the names of all qualified arbitrators on the Alternate Dispute Resolution Coordinator’s list. If the parties are unable to agree on a single arbitrator by the fourteenth day following delivery of the foregoing list of arbitrators or such other date as agreed to by the parties, then not later than the end of the seventh Business Day thereafter the party or parties demanding arbitration on the one hand, and the party or parties responding to the demand for arbitration on the other, shall each designate an arbitrator from a list for the dispute prepared by the Alternate Dispute Resolution Coordinator. The arbitrators so chosen shall then choose a third arbitrator.

4.5 Procedures.

The Alternate Dispute Resolution Coordinator shall compile and make available to the arbitrator(s) and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified in these PJM Dispute Resolution Procedures, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator(s) deem appropriate. To the extent deemed appropriate by the Alternate Dispute Resolution Coordinator, the procedures shall be based on the American Arbitration Association Rules, to the extent such Rules are not inconsistent with any rule, standard or procedure adopted by the Office of the Interconnection, or with any provision of these PJM Dispute Resolution Procedures. Upon selection of the arbitrator(s), arbitration shall go forward in accordance with applicable procedures.

4.6 Summary Disposition and Interim Measures.

4.6.1 Lack of Good Faith Basis.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator(s) does not have a good faith basis in either law or fact. If the arbitrator(s) determine(s) that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator(s) shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator(s) to the prevailing party.

4.6.2 Discovery Limits.

The procedures for the arbitration of a dispute shall provide a means for summary disposition without discovery of facts if there is no dispute as to any material fact, or with such limited discovery as the arbitrator(s) shall determine is reasonably likely to lead to the prompt resolution of any disputed issue of material fact.

4.6.3 Interim Decision.

The procedures for the arbitration of a dispute shall permit any party to a dispute to request the arbitrator(s) to render a written interim decision requiring that any action or decision that is the subject of a dispute not be put into effect, or imposing such other interim measures as the arbitrator(s) deem necessary or appropriate, to preserve the rights and obligations secured by any of the Related PJM Agreements during the pendency of the arbitration proceeding. The parties shall be bound by such written decision pending the outcome of the arbitration proceeding.

4.7 Discovery of Facts.

4.7.1 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, and (iii) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified by the procedures established by the arbitrator(s) or agreement of the parties.

4.7.2 Procedures Arbitrator.

The sole arbitrator, or the arbitrator selected by the arbitrators chosen by the parties, as the case may be (such arbitrator being hereafter referred to as the "Procedures Arbitrator"), shall be responsible for establishing the timing, amount, and means of discovery, and for resolving discovery and other pre-hearing disagreement. If a dispute involves contested issues of fact, promptly after the selection of the arbitrator(s) the Procedures Arbitrator shall convene a meeting of the parties for the purpose of establishing a schedule and plan of discovery and other pre-hearing actions.

4.8 Evidentiary Hearing.

The procedures for the arbitration of a dispute shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be as described in the Federal Rules of Evidence, except as modified by the procedures established by the arbitrator(s) or agreement of the parties. The arbitrator(s) may require such written or other submissions from the parties as shall be deemed appropriate, including submission of the direct testimony of witnesses in written form. The arbitrator(s) may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. Any party or parties may arrange for the preparation of a record of the hearing, and shall pay the costs thereof. Such party or parties shall have no obligation to provide or agree to the provision of a copy of the record of the hearing to any party that does not pay an equal share of the cost of the record. At the request of any party, the arbitrator(s) shall determine a fair and equitable allocation of the costs of the preparation of a record between or among the parties to the proceeding willing to share such costs.

4.9 Confidentiality.

4.9.1 Designation.

Any document or other information obtained in the course of an arbitral proceeding and not otherwise available to the receiving party, including any such information contained in documents or other means of recording information created during the course of the proceeding, may be designated "Confidential" by the producing party. The party producing documents or other information marked "Confidential" shall have twenty days from the production of such material to submit a request to the Procedures Arbitrator to establish such requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information and the rights of the parties, which requirements shall be binding on all parties to the dispute. Prior to the decision of the Procedures Arbitrator on a request for confidential treatment, documents or other information designated as "Confidential" shall not be used by the receiving party or parties, or the arbitrator(s), or anyone working for or on behalf of any of the foregoing, for any purpose other than the arbitration proceeding, and shall not be disclosed in any form to any person not involved in the arbitration proceeding without the prior written consent of the party producing the information or as permitted by the Procedures Arbitrator.

4.9.2 Compulsory Disclosure.

Any party receiving a request or demand for disclosure, whether by compulsory process, discovery request, or otherwise, of documents or information obtained in the course of an arbitration proceeding that have been designated "Confidential" and that are subject to a non-disclosure requirement under these PJM Dispute Resolution Procedures or a decision of the Procedures Arbitrator, shall immediately inform the party from which the information was obtained, and shall take all reasonable steps, short of incurring sanctions or other penalties, to afford the person or entity from which the information was obtained an opportunity to protect the information from disclosure. Any party disclosing information in violation of these PJM Dispute Resolution Procedures or requirements established by the Procedures Arbitrator shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

4.9.3 Public Information.

Nothing in the Related PJM Agreements shall preclude the use of documents or information properly obtained outside of an arbitral proceeding, or otherwise public, for any legitimate purpose, notwithstanding that the information was also obtained in the course of the arbitral proceeding.

4.10 Timetable.

Promptly after the selection of the arbitrator(s), the arbitrator(s) shall set a date for the issuance of the arbitral decision, which shall be not later than eight months (or such earlier date as may be agreed to by the parties to the dispute) from the date of the selection of the arbitrator(s), with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed absent extraordinary circumstances. The arbitrator(s) shall have the power to impose sanctions, including dismissal of the proceeding for dilatory tactics or undue delay in completing the arbitral proceedings.

4.11 Advisory Interpretations.

Except as to matters subject to decision in the arbitration proceeding, the arbitrator(s) may request as may be appropriate from any committee or subcommittee established under a Related PJM Agreement or by the Office of the Interconnection, an interpretation of any Related PJM Agreements, or of any standard, requirement, procedure, tariff, Schedule, principle, plan or other criterion or policy established by any committee or subcommittee. Except to the extent that the Office of the Interconnection is itself a party to a dispute, the arbitrator(s) may request the advice of the Office of the Interconnection with respect to any matter relating to a responsibility of the Office of the Interconnection under the Agreement or with respect to any of the Related PJM Agreements, or to the PJM Manuals. Any such interpretation or advice shall not relieve the arbitrator(s) of responsibility for resolving the dispute or deciding the arbitration proceeding in accordance with the standards specified herein.

4.12 Decisions.

The arbitrator(s) shall issue a written decision, including findings of fact and the legal basis for the decision. The arbitral decision shall be based on (i) the evidence in the record, (ii) the terms of the Related PJM Agreements, as applicable, (iii) applicable United States federal and state law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) relevant decisions in previous arbitration proceedings. The arbitrator(s) shall have no authority to revise or alter any provision of the Related PJM Agreements. Any arbitral decision issued pursuant to these PJM Dispute Resolution Procedures that affects matters subject to the jurisdiction of FERC under Section 205 of the Federal Power Act shall be filed with FERC.

4.13 Costs.

Unless the arbitrator(s) shall decide otherwise, the costs of the time, expenses, and other charges of the arbitrator(s) shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitral proceeding shall bear its own costs and fees. The arbitrator(s) may award all or a portion of the costs of the time, expenses, and other charges of the arbitrator(s), the costs of arbitration, attorney's fees, and the costs of mediation, if any, to any party that substantially prevails on an issue determined by the arbitrator(s) to have been raised without a substantial basis.

4.14 Enforcement.

If the decision of the arbitrator(s) is binding, the judgment may be entered on such arbitral award by any court having jurisdiction thereof; provided, however, that within one year of the issuance of the arbitral decision any party affected thereby may request FERC or any other federal, state, regulatory or judicial authority having jurisdiction to vacate, modify, or take such other action as may be appropriate with respect to any arbitral decision that is based upon an error of law, or is contrary to the statutes, rules, or regulations administered or applied by such authority. Any party making or responding to, or intervening in proceedings resulting from, any such request, shall request the authority to adopt the resolution, if not clearly erroneous, of any issue of fact expressly or necessarily decided in the arbitral proceeding, whether or not the party participated in the arbitral proceeding.

5. ALTERNATE DISPUTE RESOLUTION COORDINATOR

5.1 Responsibilities.

The duties of the Alternate Dispute Resolution Coordinator shall include the following:

i) Maintain a list of persons qualified by temperament and experience, and with technical or legal expertise in matters likely to be the subject of disputes, to serve as mediators or arbitrators under these PJM Dispute Resolution Procedures, which lists shall be updated no less than annually and shall include the names of any mediators or arbitrators recommended by any Member; and

ii) Provide to disputing parties lists of mediators, advisors or arbitrators to resolve particular disputes.

SCHEDULE 6 -
REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

References to section numbers in this Schedule 6 refer to sections of this Schedule 6, unless otherwise specified.

1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1.1 Purpose and Objectives.

This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan (also referred to as "RTEP") to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.

1.2 Conformity with NERC *Reliability Standards* and Other Applicable Reliability Criteria.

(a) NERC establishes Reliability Standards to promote the reliability, adequacy and security of the North American bulk power supply as related to the operation and planning of electric systems.

(b) ReliabilityFirst Corporation is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the geographic region described in the applicable agreements between NERC and ReliabilityFirst Corporation, as approved by the FERC, through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the ReliabilityFirst Corporation.

(c) [Reserved]

(c.01) [Reserved]

(c.02) SERC is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the VACAR subregion of SERC. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System for SERC.

(d) The Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals.

(e) The Regional Transmission Expansion Plan planning criteria shall include, Office of the Interconnection planning procedures, NERC Reliability Standards, Regional Entity reliability principles and standards, and the individual Transmission Owner FERC filed planning criteria as filed in FERC Form No. 715, and posted on the PJM website. FERC Form No. 715 material will be posted to the PJM website, subject to applicable Critical Energy Infrastructure Information (CEII) requirements.

(f) The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan.

1.3 Establishment of Committees.

(a) The Planning Committee shall be open to participation by (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates; and (v) any other interested entities or persons and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions. The Transmission Owners shall supply representatives to the Planning Committee, and other Members may provide representatives as they deem appropriate, to provide the data, information, and support necessary for the Office of the Interconnection to perform studies as required and to develop the Regional Transmission Expansion Plan.

(b) The Transmission Expansion Advisory Committee established by the Office of the Interconnection will meet periodically with representatives of the Office of the Interconnection to provide advice and recommendations to the Office of the Interconnection to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee participants shall be given an opportunity to provide advice and recommendations for consideration by the Office of the Interconnection regarding sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives in the studies and analyses to be conducted by the Office of the Interconnection. The Transmission Expansion Advisory Committee participants shall be given the opportunity to review and provide advice and recommendations on the projects to be included in the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee meetings shall include discussions addressing interregional planning issues, as required. The Transmission Expansion Advisory Committee shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates; and (v) any other interested entities or persons. The Transmission Expansion Advisory Committee shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional Planning Process Manual (PJM Manual M-14 series) and by the rules and procedures applicable to PJM committees.

(c) The Subregional RTEP Committees established by the Office of the Interconnection shall facilitate the development and review of the Local Plans. The Subregional RTEP Committees will be responsible for the initial review of the Subregional RTEP Projects, and to provide recommendations to the Transmission Expansion Advisory Committee concerning the Subregional RTEP Projects. A Subregional RTEP Committee may of its own accord or at the request of a Subregional RTEP Committee participant, also refer specific Subregional RTEP Projects to the Transmission Expansion Advisory Committee for further review, advice and recommendations.

(d) The Subregional RTEP Committees shall be responsible for the timely review of the criteria, assumptions and models used to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements, proposed solutions and written comments prior to finalizing the Local Plan, the coordination and integration of the Local Plans into the RTEP, and addressing any stakeholder issues unresolved in the Local Plan process. The Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the criteria, assumptions, and models used in local planning activities prior to finalizing the Local Plan. The Subregional RTEP Committees shall also be responsible for the timely review of the Transmission Owners' criteria, assumptions, and models used to identify Supplemental Projects that will be considered for inclusion in the Local Plan for each Subregional RTEP Committee. The Subregional RTEP Committees meetings shall include discussions addressing interregional planning issues, as required. Once finalized, the Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the Local Plans as integrated into the RTEP, prior to the submittal of the final Regional Transmission Expansion Plan to the PJM Board for approval. In addition, the Subregional RTEP Committees will provide sufficient opportunity to review and provide written comments to the Transmission Owners on any Supplemental Projects included in the Local Plan, in accordance with Additional Procedures for Planning of Supplemental Projects set forth in Tariff, Attachment M-3.

(e) The Subregional RTEP Committees shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates and (v) any other interested entities or persons.

(f) Each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions and models to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements. Each Subregional RTEP Committee shall schedule and facilitate an additional Subregional RTEP Committee meeting, per planning cycle, and as required to review the identified criteria violations and potential solutions. The Subregional RTEP Committees may facilitate additional meetings to incorporate more localized areas in the subregional planning process. At the discretion of the Office of the Interconnection, a designated Transmission Owner may facilitate Subregional RTEP Committee meeting(s), or the additional meetings incorporating the more localized areas.

(g) The Subregional RTEP Committees shall schedule and facilitate meetings regarding Supplemental Projects, as described in the Tariff, Attachment M-3.

(h) The Subregional RTEP Committees shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional

Planning Process Manual (Manual M-14 series) and by the rules and procedures applicable to PJM committees.

1.4 Contents of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering federal and state Public Policy Requirements.

(b) The Regional Transmission Expansion Plan shall reflect, consistent with the requirements of this Schedule 6, transmission enhancements and expansions; load forecasts; and capacity forecasts, including expected generation additions and retirements, demand response, and reductions in demand from energy efficiency and price responsive demand for at least the ensuing ten years.

(c) The Regional Transmission Expansion Plan shall, at a minimum, include a designation of the Transmission Owner(s) or other entity(ies) that will construct, own, maintain, operate, and/or finance each transmission enhancement and expansion and how all reasonably incurred costs are to be recovered.

(d) The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take into account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region; (v) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; and (vi) strive for consistency in planning data and assumptions that may relieve transmission congestion across multiple regions.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if: (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the Transmission System or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection in its on-going evaluation of the Transmission System's market efficiency and operational performance; (iii) required as a result of the Office of the Interconnection's assessment of the Transmission System's compliance with NERC Reliability Standards, more stringent reliability criteria, if any, or PJM planning and operating criteria; (iv) required to address constraints or available transfer capability shortages, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b), constraints or shortages as a result of expected generation retirements, constraints or shortages based on an evaluation of load forecasts, or system reliability needs arising from proposals for the addition of Transmission Facilities in the PJM Region; or (v) expansion of the Transmission System is proposed by one or more Transmission Owners, Interconnection Customers, Network Service Users or Transmission Customers, or any party that funds Network Upgrades pursuant to the Operating Agreement, Schedule 1, section 7.8. The Office of the Interconnection may initiate the enhancement and expansion study process to address or consider, where appropriate, requirements or needs arising from sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives.

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee participants of, as well as publicly notice, the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee participants shall notify the Office of the Interconnection in writing of any additional transmission considerations they would like to have included in the Office of the Interconnection's analyses.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

In conducting the enhancement and expansion studies, the Office of the Interconnection shall not limit its analyses to bright line tests to identify and evaluate potential Transmission System limitations, violations of planning criteria, or transmission needs. In addition to the bright line tests, the Office of the Interconnection shall employ sensitivity studies, modeling assumption variations, and scenario analyses, and shall also consider Public Policy Objectives in the studies and analyses, so as to mitigate the possibility that bright line metrics may inappropriately include or exclude transmission projects from the transmission plan. Sensitivity studies, modeling assumption variations, and scenario analyses shall take account of potential changes in expected future system conditions, including, but not limited to, load levels, transfer levels, fuel costs, the level and type of generation, generation patterns (including, but not limited to, the effects of assumptions regarding generation that is at risk for retirement and new generation to satisfy Public Policy Objectives), demand response, and uncertainties arising from estimated times to construct transmission upgrades. The Office of the Interconnection shall use the sensitivity studies, modeling assumption variations and scenario analyses in evaluating and choosing among alternative solutions to reliability, market efficiency and operational performance needs. The Office of the Interconnection shall provide the results of its studies and analyses to the Transmission Expansion Advisory Committee to consider the impact that sensitivities, assumptions, and scenarios may have on Transmission System needs and the need for transmission enhancements or expansions. Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential transmission expansions and enhancements, demand response programs, and other alternative technologies as appropriate to maintain system reliability.

(d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition, market efficiency, operational performance, and Public Policy Requirements in the PJM Region.

(e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to the Operating Agreement, Schedule 1, section 7.8.

(f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.

(g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and market efficiency.

(h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure that the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b). Enhancements and expansions related to stage 1A

Auction Revenue Rights identified pursuant to this Section shall be recommended for inclusion in the Regional Transmission Expansion Plan together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Operating Agreement, Schedule 6, section 1.5.3(h) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m) and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current local planning information, including all criteria, assumptions and models used by the Transmission Owners, such as those used to develop Supplemental Projects. The data required under this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region, Independent State Agencies Committee, and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study, including information regarding potential sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives that may be considered.

(d) The Office of the Interconnection shall supply to the Transmission Expansion Advisory Committee and the Subregional RTEP Committees reasonably required information and data utilized to develop the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions and Office of the Interconnection's CEII process.

(e) The Office of the Interconnection shall provide access through the PJM website, to the Transmission Owner's local planning information, including all criteria, assumptions and models used by the Transmission Owners in their internal planning processes, including the development of Supplemental Projects ("Local Plan Information"). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in the Operating Agreement, section 18.17; (2) the Office of the Interconnection's CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, the Office of the Interconnection may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in the Operating Agreement, section 18.17 and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM Interconnection, L.L.C., the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the Transmission Expansion Advisory Committee, and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the Transmission Systems of the surrounding Regional Entities and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements:

- Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C., which is found at http://www.pjm.com/~/media/documents/agreements/joa-complete.ashx;

- Northeastern ISO/RTO Planning Coordination Protocol, which is described at Schedule 6-B and found at http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx;

- Joint Operating Agreement Among and Between New York Independent System Operator Inc., which is found at http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx;

- Interregional Transmission Coordination Between the SERTP and PJM Regions, which is found at Operating Agreement, Schedule 6-A ;

- Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions, which is located at Tariff, Schedule 12-B;

- Joint Reliability Coordination Agreement Between PJM Interconnection, L.L.C., Tennessee Valley Authority, and Louisville Gas and Electric Company and Kentucky Utilities.

(i) Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.

(ii) An entity, including existing Transmission Owners and Nonincumbent Developers, may submit potential Interregional Transmission Projects pursuant to the Operating Agreement, Schedule 6, section 1.5.8.

(c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

(d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies, including sensitivity studies and scenario analyses on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committees.

(b) The Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the Regional Transmission Expansion Plan process. The purpose of the assumptions meeting shall be to provide an open forum to discuss the following: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) Public Policy Requirements identified by the states for consideration in the Office of the Interconnection's transmission planning analyses; (iii) Public Policy Objectives identified by stakeholders for consideration in the Office of the Interconnection's transmission planning analyses; (iv) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, price responsive demand, generating additions and retirements, market efficiency and other trends in the industry; and (v) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by the Committee participants. Prior to the initial assumptions meeting, the Transmission Expansion Advisory Committee and Subregional RTEP Committees participants will be afforded the opportunity to provide input and submit suggestions regarding the information identified in items (i) through (v) of this subsection. Following the assumptions meeting and prior to performing the evaluation and analyses of transmission needs, the Office of the Interconnection shall determine the range of assumptions to be used in the studies and scenario analyses, based on the advice and recommendations of the Transmission Expansion Advisory Committee and Subregional RTEP Committees and, through the Independent State Agencies, the statement of Public Policy Requirements provided individually by the states and any state member's assessment or prioritization of Public Policy Objectives proposed by other stakeholders. The Office of the Interconnection shall document and publicly post its determination for review. Such posting shall include an explanation of those Public Policy Requirements and Public Policy Objectives adopted at the assumptions stage to be used in performing the evaluation and analysis of transmission needs. Following identification of transmission needs and prior to evaluating potential enhancements and expansions to the Transmission System the Office of the Interconnection shall publicly post all transmission need information identified as described further in the Operating Agreement, Schedule 6, section 1.5.8(b) herein to support the role of the Subregional RTEP Committees in the development of the Local Plan and support the role of Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection shall also post an explanation of why other Public Policy Requirements and Public Policy Objectives introduced by stakeholders at the assumptions stage were not adopted.

(c) The Subregional RTEP Committees shall also schedule and facilitate meetings related to Supplemental Projects, as described in the Tariff, Attachment M-3.

(d) After the assumptions meeting(s), the Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants (as defined in the Operating Agreement, Schedule 6, sections 1.3(b) and 1.3(c)) to review, evaluate and offer comments and alternatives to the following arising from the studies performed by the Office of the Interconnection, including sensitivity studies and scenario analyses: (i) any identified violations of reliability criteria and analyses of the market efficiency and operational performance of the Transmission System; (ii) potential transmission solutions, including any acceleration, deceleration or modifications of a potential expansion or enhancement based on the results of sensitivities studies and scenario analyses; and (iii) the proposed Regional Transmission Expansion Plan. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the Regional Transmission Expansion Plan at these meetings or at the regularly scheduled meetings of the Planning Committee.

(e) In addition, the Office of the Interconnection shall facilitate periodic meetings with the Independent State Agencies Committee to discuss: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) regulatory initiatives, as appropriate, including state regulatory agency initiated programs, and other Public Policy Objectives, to consider including in the Office of the Interconnection's transmission planning analyses; (iii) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, generating capacity, market efficiency and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by Independent State Agencies Committee. At such meetings, the Office of the Interconnection also shall discuss the current status of the enhancement and expansion study process. The Independent State Agencies Committee may request that the Office of Interconnection schedule additional meetings as necessary. The Office of the Interconnection shall inform the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, of the input of the Independent State Agencies Committee and shall consider such input in developing the range of assumptions to be used in the studies and scenario analyses described in section (b), above.

(f) Upon completion of its studies and analysis, including sensitivity studies and scenario analyses the Office of the Interconnection shall post on the PJM website the violations, system conditions, economic constraints, and Public Policy Requirements as detailed in the Operating Agreement, Schedule 6, section 1.5.8(b) to afford entities an opportunity to submit proposed enhancements or expansions to address the posted violations, system conditions, economic constraints and Public Policy Requirements as provided for in the Operating Agreement, Schedule 6, section 1.5.8(c). Following the close of a proposal window, the Office of the Interconnection shall: (i) post all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c); (ii) consider proposals submitted during the proposal windows consistent with the Operating Agreement, Schedule 6, section 1.5.8(d) and develop a recommended plan. Following review by the Transmission Expansion Advisory Committee of proposals, the Office of the Interconnection, based on identified needs and the timing of such needs, and taking into account the sensitivity studies, modeling assumption variations and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall determine, which more efficient or cost-effective enhancements and expansions shall be included in the recommended plan, including solutions identified as a result of the sensitivity studies, modeling assumption variations, and scenario analyses, that may accelerate, decelerate or modify a potential reliability, market efficiency or operational performance expansion or enhancement identified as a result of the sensitivity studies, modeling assumption variations and scenario analyses, shall be included in the recommended plan. The Office of the Interconnection shall post the proposed recommended plan for review and comment by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection before submitting the recommended plan to the PJM Board for approval.

(g) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committees.

(h) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(i) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in the Operating Agreement, Schedule 6, sections 1.5.7 and 1.5.8.

(j) The recommended plan shall identify enhancements and expansions proposed by a state or states pursuant to the Operating Agreement, Schedule 6, section 1.5.9.

(k) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to the Operating Agreement, Schedule 6, section 1.1, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of the Tariff, Parts IV and VI; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by the Tariff, Parts IV and VI with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(l) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of the Operating Agreement, Schedule 1, section 7.8, or to facilitate upgrades pursuant to the Tariff, Parts II, III, or VI, and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. Any designation under this paragraph of one or more entities to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of partial responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(m) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to the Tariff, Schedule 12, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B) subject to FERC review and approval, shall be incorporated in any amendment to the Tariff, Schedule 12 that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under the Operating Agreement, Schedule 6, sections 1.5.6(i) and 1.5.7, (C) the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7 shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under the Tariff, Schedule 12, section (b) for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in the Tariff, Attachment DD, section 15 shall (1) be allocated across Zones based on each Zone's pro rata share of load in such LDA and (2) within each Zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(n) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, market efficiency or operational performance, pursuant to a determination by the Office of the Interconnection. These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

1.5.7 Development of Economic-based Enhancements or Expansions.

(a) Each year the Transmission Expansion Advisory Committee shall review and comment on the assumptions to be used in performing the market efficiency analysis to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each year, each Transmission Owner will be requested to provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment. Following review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection shall submit the assumptions to be used in performing the market efficiency analysis described in this Operating Agreement, Schedule 6, section 1.5.7 to the PJM Board for consideration.

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in the Operating Agreement, Schedule 1, section 7.4.2(c); or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items in the Operating Agreement, Schedule 6, section 1.5.7(b)(i-iii) is described in the PJM Manuals.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan, which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory

Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional Economic-based Enhancements or Expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), any market participant may submit to the Office of the Interconnection a proposal to construct an additional Economic-based Enhancement or Expansion to relieve an economic constraint. Upon completion of its evaluation, including consideration of any eligible market participant proposed Economic-based Enhancements or Expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of new Economic-based Enhancements or Expansions for review and comment. Upon consideration and advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new Economic-based Enhancements or Expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional Economic-based Enhancements or Expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional Economic-based Enhancements or Expansions pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m). In the event the entity or entities designated as responsible for construction, owning or financing a designated new Economic-based Enhancement or Expansion declines to construct, own or finance the new Economic-based Enhancement or Expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with the Operating Agreement, Schedule 6, sections 1.6 and 1.7. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional Economic-based Enhancements or Expansions and whether such Economic-based Enhancements or Expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional Economic-based Enhancements or Expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this Operating Agreement, Schedule 6, section 1.5.7(d). An Economic-based Enhancement or Expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the Economic-based Enhancement or Expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for the 15 year *period starting with the RTEP Year (defined as current year plus five) minus benefits for years when the project is not yet in-service*] ÷ [Present value of the Total Enhancement Cost for the *same* 15 year *period*]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Energy Market Benefit is as follows:

Energy Market Benefit = [.50] * [Change in Total Energy Production Cost] + [.50] * [Change in Load Energy Payment]

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Energy Market Benefit is as follows:

Energy Market Benefit = [1] * [Change in Load Energy Payment]
and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the Economic-based Enhancement or Expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the Economic-based Enhancement or Expansion]. The change in costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured, if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)] – [the change in value of transmission rights for each Zone with the Economic-based Enhancement or Expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion)]. The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.

And

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [.50] * [Change in Total System Capacity Cost] + [.50] * [Change in Load Capacity Payment]

and

For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [1] * [Change in Load Capacity Payment]

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal

Capacity Prices under the Tariff, Attachment DD without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion. The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new Economic-based Enhancement or Expansion, the Office of the Interconnection shall calculate and post on the PJM website the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the

Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new Economic-based Enhancements or Expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the Economic-based Enhancement or Expansion, and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of the Operating Agreement, Schedule 6, section 1.5.7(i). The Office of the Interconnection will not be required to review annually the costs and benefits of constructing Economic-based Enhancements or Expansions with capital costs less than $20 million if, based on updated cost estimates and the original benefits, the Benefit/Cost Ratio remains at or above 1.25. The Office of the Interconnection shall no longer be required to review costs and benefits of constructing Economic-based Enhancements and Expansions once: (i) a certificate of public convenience and necessity or its equivalent is granted by the state or relevant regulatory authority in which such enhancements or expansions will be located; or (ii) if a certificate of public convenience and necessity or its equivalent is not required by the state or relevant regulatory authority in which an economic-based enhancement or expansion will be located, once construction activities commence at the project site.

(g) For new economic enhancements or expansions with costs in excess of $50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new Economic-based Enhancements or Expansions is consistent with the new Economic-based Enhancements or Expansions as recommended in the market efficiency analysis.

(h) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to the Tariff, Parts IV and VI that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a “market solution” and, in the event of such designation, the Tariff, Part VI, Subpart B, section 216, as applicable, shall apply to the project.

(i) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

(i) Timely installation of Qualifying Transmission Upgrades, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(ii) Availability of Generation Capacity Resources, as defined by the RAA, section 1.33, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iii) Availability of Demand Resources that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iv) Addition of Customer Facilities pursuant to an executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed. Facilities with an executed Facilities Study Agreement or suspended Interconnection Service Agreement may be included by the Office of the Interconnection after review with the Transmission Expansion Advisory Committee.

(v) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

(vi) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.

(vii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues and Capacity Resource Clearing Prices under the Tariff, Attachment DD. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model Customer Facilities pursuant to an executed Facilities Study Agreement or suspended Interconnection Service Agreement, ranked by their commercial probability. Commercial probability utilizes historical data from the PJM interconnection queues to determine the likelihood of a Customer Facility, pursuant to an executed Facilities Study Agreement or suspended Interconnection Service Agreement, reaching commercial operation. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses, following inclusion of the Customer Facilities discussed above in this section 1.5.7(i)(vii), then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues and, if necessary, add transmission enhancements to address congestion that arises from such modeling.

(viii) Items (i) through (v) will be included in the market efficiency assumptions if qualified for consideration by the PJM Board. In the event that any of the items listed in (i) through (v) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an Economic-based Enhancement or Expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) that the need for the Economic-based Enhancement or Expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(j) For informational purposes only, with regard to Economic-based Enhancements or Expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses consistent with the Operating Agreement, Schedule 6, section 1.5.3 and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

1.5.8 Development of Long-lead Projects, Short-term Projects, Immediate-need Reliability Projects, and Economic-based Enhancements or Expansions.

(a) **Pre-Qualification Process**.

(a)(1) On September 1 of each year, the Office of the Interconnection shall open a thirty-day pre-qualification window for entities, including existing Transmission Owners and Nonincumbent Developers, to submit to the Office of the Interconnection: (i) applications to pre-qualify as eligible to be a Designated Entity; or (ii) updated information as described in the Operating Agreement, Schedule 6, section 1.5.8(a)(3). Pre-qualification applications shall contain the following information: (i) name and address of the entity; (ii) the technical and engineering qualifications of the entity or its affiliate, partner, or parent company; (iii) the demonstrated experience of the entity or its affiliate, partner, or parent company to develop, construct, maintain, and operate transmission facilities, including a list or other evidence of transmission facilities the entity, its affiliate, partner, or parent company previously developed, constructed, maintained, or operated; (iv) the previous record of the entity or its affiliate, partner, or parent company regarding construction, maintenance, or operation of transmission facilities both inside and outside of the PJM Region; (v) the capability of the entity or its affiliate, partner, or parent company to adhere to standardized construction, maintenance and operating practices; (vi) the financial statements of the entity or its affiliate, partner, or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the entity, if shorter, or such other evidence demonstrating an entity's or its affiliate's, partner's, or parent company's current and expected financial capability acceptable to the Office of the Interconnection; (vii) a commitment by the entity to execute the Consolidated Transmission Owners Agreement, if the entity becomes a Designated Entity; (viii) evidence demonstrating the ability of the entity or its affiliate, partner, or parent company to address and timely remedy failure of facilities; (ix) a description of the experience of the entity or its affiliate, partner, or parent company in acquiring rights of way; and (x) such other supporting information that the Office of Interconnection requires to make the pre-qualification determinations consistent with this Operating Agreement, Schedule 6, section 1.5.8(a).

(a)(2) No later than October 31, the Office of the Interconnection shall notify the entities that submitted pre-qualification applications or updated information during the annual thirty-day pre-qualification window, whether they are, or will continue to be, pre-qualified as eligible to be a Designated Entity. In the event the Office of the Interconnection determines that an entity (i) is not, or no longer will continue to be, pre-qualified as eligible to be a Designated Entity, or (ii) provided insufficient information to determine pre-qualification, the Office of the Interconnection shall inform that the entity it is not pre-qualified and include in the notification the basis for its determination. The entity then may submit additional information, which the Office of the Interconnection shall consider in re-evaluating whether the entity is, or will continue to be, pre-qualified as eligible to be a Designated Entity. If the entity submits additional information by November 30, the Office of the Interconnection shall notify the entity of the results of its re-evaluation no later than December 15. If the entity submits additional information after November 30, the Office of the Interconnection shall use reasonable efforts to re-evaluate the application, with the additional information, and notify the entity of its determination as soon as practicable. No later than December 31, the Office of the Interconnection shall post on the PJM website the list of entities that are pre-qualified as eligible to be Designated Entities. If an entity is notified by the Office of the Interconnection that it does not pre-qualify or will not continue to be pre-qualified as eligible to be a Designated Entity, such entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5.

(a)(3) In order to continue to pre-qualify as eligible to be a Designated Entity, such entity must confirm its information with the Office of the Interconnection no later than three years following its last submission or sooner if necessary as required below. In the event the information on which the entity's pre-qualification is based changes with respect to the upcoming year, such entity must submit to the Office of the Interconnection all updated information during the annual thirty-day pre-qualification window and the timeframes for notification in the Operating Agreement, Schedule 6, section 1.5.8(a)(2) shall apply. In the event the information on which the entity's pre-qualification is based changes with respect to the current year, such entity must submit to the Office of the Interconnection all updated information at the time the information changes and the Office of the Interconnection shall use reasonable efforts to evaluate the updated information and notify the entity of its determination as soon as practicable.

(a)(4) As determined by the Office of the Interconnection, an entity may submit a pre-qualification application outside the annual thirty-day pre-qualification window for good cause shown. For a pre-qualification application received outside of the annual thirty-day pre-qualification window, the Office of the Interconnection shall use reasonable efforts to process the application and notify the entity as to whether it pre-qualifies as eligible to be a Designated Entity as soon as practicable.

(a)(5) To be designated as a Designated Entity for any project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8, existing Transmission Owners and Nonincumbent Developers must be pre-qualified as eligible to be a Designated Entity pursuant to this Operating Agreement, Schedule 6, section 1.5.8(a). This Operating Agreement, Schedule 6, section 1.5.8(a) shall not apply to entities that desire to propose projects for inclusion in the recommended plan but do not intend to be a Designated Entity.

(b) **Posting of Transmission System Needs**. Following identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Operating Agreement, Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, and prior to evaluating potential enhancements and expansions to the Transmission System, the Office of the Interconnection shall publicly post on the PJM website all transmission need information, including violations, system conditions, and economic constraints, and Public Policy Requirements, including (i) federal Public Policy Requirements; (ii) state Public Policy Requirements identified or agreed-to by the states in the PJM Region, which could be addressed by potential Short-term Projects, Long-lead Projects or projects determined pursuant to the State Agreement Approach in the Operating Agreement, Schedule 6, section 1.5.9, as applicable. Such posting shall support the role of the Subregional RTEP Committees in the development of the Local Plans and support the role of the Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection also shall post an explanation regarding why transmission needs associated with federal or state Public Policy Requirements were identified but were not selected for further evaluation.

(c) **Project Proposal Windows**. The Office of the Interconnection shall provide notice to stakeholders of a 60-day proposal window for Short-term Projects and a 120-day proposal window for Long-lead Projects and Economic-based Enhancements or Expansions. The specifics regarding whether or not the following types of violations or projects are subject to a proposal window are detailed in the Operating Agreement, Schedule 6, section 1.5.8(m) for Immediate-need Reliability Projects; Operating Agreement, Schedule 6, section 1.5.8(n) for reliability violations on transmission facilities below 200 kV; and Operating Agreement, Schedule 6, section 1.5.8(p) for violations on transmission substation equipment. The Office of Interconnection may shorten a proposal window should an identified need require a shorter proposal window to meet the needed in-service date of the proposed enhancements or expansions, or extend a proposal window as needed to accommodate updated information regarding system conditions. The Office of the Interconnection may shorten or lengthen a proposal window that is not yet opened based on one or more of the following criteria: (1) complexity of the violation or system condition; and (2) whether there is sufficient time remaining in the relevant planning cycle to accommodate a standard proposal window and timely address the violation or system condition. The Office of the Interconnection may lengthen a proposal window that already is opened based on or more of the following criteria: (i) changes in assumptions or conditions relating to the underlying need for the project, such as load growth or Reliability Pricing Model auction results; (ii) availability of new or changed information regarding the nature of the violations and the facilities involved; and (iii) time remaining in the relevant proposal window. In the event that the Office of the Interconnection determines to lengthen or shorten a proposal window, it will post on the PJM website the new proposal window period and an explanation as to the reasons for the change in the proposal window period. During these windows, the Office of the Interconnection will accept proposals from existing Transmission Owners and Nonincumbent Developers for potential enhancements or expansions to address the posted violations, system conditions, economic constraints, as well as Public Policy Requirements.

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals submitted with cost estimates of $5 million or less, a $5,000 non-refundable deposit must be included with each project proposal submitted by a proposing entity that indicates an intention to be the Designated Entity.

(c)(1)(i) In addition, any proposing entity indicating its intention to be the Designated Entity will be responsible for and must pay all actual costs incurred by the Transmission Provider to evaluate the submitted project proposal. To the extent the Transmission Provider incurs costs to evaluate multiple submitted project proposals where such costs are not severable by individual project proposal, the Transmission Provider shall invoice equal shares of the non-severable costs among the project proposals that cause such non-severable costs to be incurred. Notwithstanding this method of invoicing non-severable costs, non-severable costs will be jointly and severally owed by the proposing entities that cause such costs to be incurred.

(c)(1)(ii) All non-refundable deposits will be credited towards the actual costs incurred by the Transmission Provider as a result of the evaluation of a submitted project proposal.

(c)(1)(iii) Following the close of a proposal window but before the Transmission Provider incurs any third-party consultant work costs to evaluate a submitted project proposal, the Transmission Provider will issue to the proposing entity an initial invoice seeking payment of estimated costs to evaluate each submitted project proposal. The estimated costs will be determined by considering the: potential cost of consultant work, historical estimates for project proposals of similar scope, complexity and nature of the need, and/or technology and nature of the project proposal. The Transmission Provider may issue additional invoices to the proposing entity prior to the completion of the evaluation activities associated with a project proposal if the Transmission Provider receives updated actual cost information and/or upon consideration of the factors specified in this section.

(c)(1)(iv) At the completion of the evaluation activities associated with a project proposal, the Transmission Provider will reconcile the actual costs with monies paid and, to the extent necessary, issue either a final invoice or refund.

(c)(1)(v) The proposing party must pay any invoiced costs within fifteen (15) calendar days of the Transmission Provider sending the invoice to the proposing entity or its agent. For good cause shown, this fifteen (15) calendar day time period may be extended by the Transmission Provider. If the proposing entity fails to pay any invoice within the time period specified and/or extended by the Transmission Provider in accordance with this section, the proposing entity's pre-qualification status may be suspended and the proposing entity will be ineligible to be a Designated Entity for any projects that do not yet have an executed Designated Entity Agreement. Such a suspension and/or ineligibility will remain in place until the proposing entity pays in full all outstanding monies owed to the Transmission Provider as a result of the evaluation of the proposing entity's project proposal(s).

(c)(2) Proposals from all entities (both existing Transmission Owners and Nonincumbent Developers) that indicate the entity intends to be a Designated Entity, also must contain information to the extent not previously provided pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) demonstrating: (i) technical and engineering qualifications of the entity, its affiliate, partner, or parent company relevant to construction, operation, and maintenance of the proposed project; (ii) experience of the entity, its affiliate, partner, or parent company in developing, constructing, maintaining, and operating the type of transmission facilities contained in the project proposal; (iii) the emergency response capability of the entity that will be operating and maintaining the proposed project; (iv) evidence of transmission facilities the entity, its affiliate, partner, or parent company previously constructed, maintained, or operated; (v) the ability of the entity or its affiliate, partner, or parent company to obtain adequate financing relative to the proposed project, which may include a letter of intent from a financial institution approved by the Office of the Interconnection or such other evidence of the financial resources available to finance the construction, operation, and maintenance of the proposed project; (vi) the managerial ability of the entity, its affiliate, partner, or parent company to contain costs and adhere to construction schedules for the proposed project, including a description of verifiable past achievement of these goals; (vii) a demonstration of other advantages the entity may have to construct, operate, and maintain the proposed project, including any binding cost commitment proposal the entity may wish to submit; and (viii) any other information that may assist the Office of the Interconnection in evaluating the proposed project. To the extent that an entity submits a cost containment proposal the entity shall submit sufficient information for the Office of Interconnection to determine the binding nature of the proposal with respect to critical elements of project development. PJM may not alter the requirements for proposal submission to require the submission of a binding cost containment proposal, in whole or in part, or otherwsise mandate or unilaterally alter the terms of any such proposal or the requirements for proposal submission, the submission of any such proposals at all times remaining voluntary.

(c)(3) The Office of the Interconnection may request additional reports or information from an existing Transmission Owner or Nonincumbent Developers that it determines are reasonably necessary to evaluate its specific project proposal pursuant to the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). If the Office of the Interconnection determines any of the information provided in a proposal is deficient or it requires additional reports or information to analyze the submitted proposal, the Office of the Interconnection shall notify the proposing entity of such deficiency or request. Within 10 Business Days of receipt of the notification of deficiency and/or request for additional reports or information, or other reasonable time period as determined by the Office of the Interconnection, the proposing entity shall provide the necessary information.

(c)(4) The request for additional reports or information by the Office of the Interconnection pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c)(3) may be used only to clarify a proposed project as submitted. In response to the Office of the Information's request for additional reports or information, the proposing entity (whether an existing Transmission Owner or Nonincumbent Developer) may not submit a new project proposal or modifications to a proposed project once the proposal window is closed. In the event that the proposing entity fails to timely cure the deficiency or provide the requested reports or information regarding a proposed project, the proposed project will not be considered for inclusion in the recommended plan.

(c)(5) Within 30 days of the closing of the proposal window, the Office of the Interconnection may notify the proposing entity that additional per project fees are required if the Office of the Interconnection determines the proposing entity's submittal includes multiple project proposals. Within 10 Business Days of receipt of the notification of insufficient funds by the Office of the Interconnection, the proposing entity shall submit such funds or notify the Office of the Interconnection which of the project proposals the Office of the Interconnection should evaluate based on the fee(s) submitted.

(d) **Posting and Review of Projects**. Following the close of a proposal window, the Office of the Interconnection shall post on the PJM website all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). All proposals addressing state Public Policy Requirements shall be provided to the applicable states in the PJM Region for review and consideration as a Supplemental Project or a state public policy project consistent with the Operating Agreement, Schedule 6, section 1.5.9. The Office of the Interconnection shall review all proposals submitted during a proposal window and determine and present to the Transmission Expansion Advisory Committee the proposals that merit further consideration for inclusion in the recommended plan. In making this determination, the Office of the Interconnection shall consider the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee for review and comment descriptions of the proposed enhancements and expansions, including any proposed Supplemental Projects or state public policy projects identified by a state(s). Based on review and comment by the

Transmission Expansion Advisory Committee, the Office of the Interconnection may, if necessary conduct further study and evaluation. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee the revised enhancements and expansions for review and comment. After consultation with the Transmission Expansion Advisory Committee, the Office of the Interconnection shall determine the more efficient or cost-effective transmission enhancements and expansions for inclusion in the recommended plan consistent with this Operating Agreement, Schedule 6.

(e) **Criteria for Considering Inclusion of a Project in the Recommended Plan**. In determining whether a Short-term Project or Long-lead Project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), individually or in combination with other Short-term Projects or Long-lead Projects, is the more efficient or cost-effective solution and therefore should be included in the recommended plan, the Office of the Interconnection, taking into account sensitivity studies and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall consider the following criteria, to the extent applicable: (i) the extent to which a Short-term Project or Long-lead Project would address and solve the posted violation, system condition, or economic constraint; (ii) the extent to which the relative benefits of the project meets a Benefit/Cost Ratio Threshold of at least 1.25:1 as calculated pursuant to the Operating Agreement, Schedule 6, section 1.5.7(d); (iii) the extent to which the Short-term Project or Long-lead Project would have secondary benefits, such as addressing additional or other system reliability, operational performance, economic efficiency issues or federal Public Policy Requirements or state Public Policy Requirements identified by the states in the PJM Region; and (iv) the ability to timely complete the project, and project development feasibility; and (v) other factors such as cost-effectiveness, including the quality and effectiveness of any voluntary-submitted binding cost commitment proposal related to Transmission Facilities which caps project construction costs (either in whole or in part), project total return on equity (including incentive adders), or capital structure. In scrutinizing the cost of project proposals, the Office of Interconnection shall determine for each project finalist's proposal, including any Transmission Owner Upgrades, the comparative risks to be borne by ratepayers as a result of the proposal's binding cost commitment or the use of non-binding cost estimates. Such comparative analysis shall detail, in a clear and transparent manner, the method by which the Office of Interconnection scrutinized the cost and overall cost-effectiveness of each finalist's proposal, including any binding cost commitments. Such comparative analysis shall be presented to the TEAC for review and comment. In evaluating any cost, ROE and/or capital structure proposal, PJM is not making a determination that the cost, ROE or capital structure results in just and reasonable rates, which shall be addressed in the required rate filing with the FERC. Stakeholders seeking to dispute a particular ROE analysis utilized in the selection process may address such disputes with the Designated Entity in the applicable rate proceeding where the Designated Entity seeks approval of such rates from the Commission. PJM may modify the technical specifications of a proposal, as outlined in the PJM Manuals, which may result in the modified proposal being determined to be the more efficient or cost-effective proposal for recommendation to the PJM Board. Neither PJM, the Designated Entity nor any stakeholders are waiving any of their respective FPA section 205 or 206 rights through this process. Challenges to the Designated Entity Agreements are subject to the just and reasonable standard.

(f) **Entity-Specific Criteria Considered in Determining the Designated Entity for a Project**. In determining whether the entity proposing a Short-term Project, Long-lead Project or Economic-based Enhancement or Expansion recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is pre-qualified to be a Designated Entity pursuant to Operating Agreement, Schedule 6, section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

(g) **Procedures if No Long-lead Project or Economic-based Enhancement or Expansion Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Long-lead Projects received during the Long-lead Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation, or system condition, the Office of the Interconnection may re-evaluate and re-post on the PJM website the unresolved violations, or system conditions pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b), provided such re-evaluation and re-posting would not affect the ability of the Office of the Interconnection to timely address the identified reliability need. In the event that re-posting and conducting such re-evaluation would prevent the Office of the Interconnection from timely addressing the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion, the Office of the Interconnection shall propose a project to solve the posted violation, or system condition for inclusion in the recommended plan and shall present such project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the project is to be located shall be the Designated Entity(ies) for such project. In determining whether there is insufficient time for re-posting and re-evaluation, the Office of the Interconnection shall develop and post on the PJM website a transmission solution construction timeline for input and review by the Transmission Expansion Advisory Committee that will include factors such as, but not limited to: (i) deadlines for obtaining regulatory approvals, (ii) dates by which long lead equipment should be acquired, (iii) the time necessary to complete a proposed solution to meet the required in-service date, and (iv) other time-based factors impacting the feasibility of achieving the required in-service date. Based on input from the Transmission Expansion Advisory Committee and the time frames set forth in the construction timeline, the Office of the Interconnection shall determine whether there is sufficient time to conduct a re-evaluation and re-post and timely address the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion. To the extent that an economic constraint remains unaddressed, the economic constraint will be re-evaluated and re-posted.

(h) **Procedures if No Short-term Project Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Short-term Projects received during a Short-term Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation or system condition, the Office of the Interconnection shall propose a Short-term Project to solve the posted violation, or system condition for inclusion in the recommended plan and will present such Short-term Project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the Short-term Project is to be located shall be the Designated Entity(ies) for the Project.

(i) **Notification of Designated Entity**. Within 15 Business Days of PJM Board approval of the Regional Transmission Expansion Plan, the Office of the Interconnection shall notify the entities that have been designated as the Designated Entities for projects included in the Regional Transmission Expansion Plan of such designations. In such notices, the Office of the Interconnection shall provide: (i) the needed in-service date of the project; and (ii) a date by which all necessary state approvals should be obtained to timely meet the needed in-service date of the project. The Office of the Interconnection shall use these dates as part of its on-going monitoring of the progress of the project to ensure that the project is completed by its needed in-service date.

(j) **Acceptance of Designation**. Within 30 days of receiving notification of its designation as a Designated Entity, the existing Transmission Owner or Nonincumbent Developer shall notify the Office of the Interconnection of its acceptance of such designation and submit to the Office of the Interconnection a development schedule, which shall include, but not be limited to, milestones necessary to develop and construct the project to achieve the required in-service date, including milestone dates for obtaining all necessary authorizations and approvals, including but not limited to, state approvals. For good cause shown, the Office of the Interconnection may extend the deadline for submitting the development schedule. The Office of the Interconnection then shall review the development schedule and within 15 days or other reasonable time as required by the Office of the Interconnection: (i) notify the Designated Entity of any issues regarding the development schedule identified by the Office of the Interconnection that may need to be addressed to ensure that the project meets its needed in-service date; and (ii) tender to the Designated Entity an executable Designated Entity Agreement setting forth the rights and obligations of the parties. To retain its status as a Designated Entity, within 60 days of receiving an executable Designated Entity Agreement (or other such period as mutually agreed upon by the Office of the Interconnection and the Designated Entity), the Designated Entity (both existing Transmission Owners and Nonincumbent Developers) shall submit to the Office of the Interconnection a letter of credit as determined by the Office of Interconnection to cover the incremental costs of construction resulting from reassignment of the project, and return to the Office of the Interconnection an executed Designated Entity Agreement containing a mutually agreed upon development schedule. In the alternative, the Designated Entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5, or request that the Designated Entity Agreement be filed unexecuted with the Commission.

(k) **Failure of Designated Entity to Meet Milestones**. In the event the Designated Entity fails to comply with one or more of the requirements of the Operating Agreement, Schedule 6, section 1.5.8(j); or fails to meet a milestone in the development schedule set forth in the Designated Entity Agreement that causes a delay of the project's in-service date, the Office of the Interconnection shall re-evaluate the need for the Short-term Project or Long-lead Project, and based on that re-evaluation may: (i) retain the Short-term Project or Long-lead Project in the Regional Transmission Expansion Plan; (ii) remove the Short-term Project or Long-lead Project from the Regional Transmission Expansion Plan; or (iii) include an alternative solution in the Regional Transmission Expansion Plan. If the Office of the Interconnection retains the Short-term or Long-term Project in the Regional Transmission Expansion Plan, it shall determine whether the delay is beyond the Designated Entity's control and whether to retain the Designated Entity or to designate the Transmission Owner(s) in the Zone(s) where the project is located as Designated Entity(ies) for the Short-term Project or Long-lead Project. If the Designated Entity is the Transmission Owner(s) in the Zone(s) where the project is located, the Office of the Interconnection shall seek recourse through the Consolidated Transmission Owners Agreement or FERC, as appropriate. Any modifications to the Regional Transmission Expansion Plan pursuant to this section shall be presented to the Transmission Expansion Advisory Committee for review and comment and approved by the PJM Board.

(l) **Transmission Owners Required to be the Designated Entity**. Notwithstanding anything to the contrary in this Operating Agreement, Schedule 6, section 1.5.8, in all events, the Transmission Owner(s) in whose Zone(s) a project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) is to be located will be the Designated Entity for the project, when the Short-term Project or Long-lead Project is: (i) a Transmission Owner Upgrade; (ii) located solely within a Transmission Owner's Zone and the costs of the project are allocated solely to the Transmission Owner's Zone; (iii) located solely within a Transmission Owner's Zone and is not selected in the Regional Transmission Expansion Plan for purposes of cost allocation; or (iv) proposed to be located on a Transmission Owner's existing right of way and the project would alter the Transmission Owner's use and control of its existing right of way under state law. Transmission Owner shall be the Designated Entity when required by state law, regulation or administrative agency order with regard to enhancements or expansions or portions of such enhancements or expansions located within that state.

(m) **Immediate-need Reliability Projects**:

(m)(1) Pursuant to the expansion planning process set forth in Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify immediate reliability needs that must be addressed within three years or less. For those immediate reliability needs for which PJM determines a proposal window may not be feasible, PJM shall identify and post such immediate need reliability criteria violations and system conditions for review and comment by the Transmission Expansion Advisory Committee and other stakeholders. Following review and comment, the Office of the Interconnection shall develop Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. The Office of the Interconnection shall consider the following factors in determining the infeasibility of such a proposal window: (i) nature of the reliability criteria violation; (ii) nature and type of potential solution required; and (iii) projected construction time for a potential solution to the type of reliability criteria violation to be addressed. The Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. Stakeholders shall be afforded no less than ten days to review Immediate-need Reliability Project materials prior to providing comments at stakeholder meetings. However, PJM may review Immediate-need Reliability Project materials with stakeholders without the requisite ten-day notice so long as: (i) stakeholders do not object to reviewing the materials or (ii) PJM identifies in its posting to the meeting materials extenuating circumstances identified by PJM that require review of the materials at the stakeholder meeting. The descriptions shall include an explanation of the decision to designate the Transmission Owner as the Designated Entity for the Immediate-need Reliability Project rather than conducting a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2), including an explanation of the time-sensitive need for the Immediate-need Reliability Project, other transmission and non-transmission options that were considered but concluded would not sufficiently address the immediate reliability need, the circumstances that generated the immediate reliability need, and why the immediate reliability need was not identified earlier. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments to the Office of the Interconnection. All comments received by the Office of the Interconnection shall be publicly available on the PJM website. Based on the comments received from stakeholders and the review by Transmission Expansion Advisory Committee, the Office of the Interconnection shall, if necessary, conduct further study and evaluation and post a revised recommended plan for review and comment by the Transmission Expansion Advisory Committee. The PJM Board shall approve the Immediate-need Reliability Projects for inclusion in the recommended plan. In January of each year, the Office of the Interconnection shall post on the PJM website and file with the Commission for informational purposes a list of the Immediate-need Reliability Projects for which an existing Transmission Owner was designated in the prior year as the Designated Entity in accordance with this Operating Agreement, Schedule 6, section 1.5.8(m)(1). The list shall include the need-by date of Immediate-need Reliability Project and the date the Transmission Owner actually energized the Immediate-need Reliability Project.

(m)(2) If, in the judgment of the Office of the Interconnection, there is sufficient time for the Office of the Interconnection to accept proposals in a shortened proposal window for Immediate-need Reliability Projects, the Office of the Interconnection shall post on the PJM website the violations and system conditions that could be addressed by Immediate-need Reliability Project proposals, including an explanation of the time-sensitive need for an Immediate-need Reliability Project and provide notice to stakeholders of a shortened proposal window. Proposals must contain the information required in the Operating Agreement, Schedule 6, section 1.5.8(c) and, if the entity is seeking to be the Designated Entity, such entity must have pre-qualified to be a Designated Entity pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a). In determining the more efficient or cost-effective proposed Immediate-need Reliability Project for inclusion in the recommended plan, the Office of the Interconnection shall consider the extent to which the proposed Immediate-need Reliability Project, individually or in combination with other Immediate-need Reliability Projects, would address and solve the posted violations or system conditions and other factors such as cost-effectiveness, the ability of the entity to timely complete the project, and project development feasibility in light of the required need. After PJM Board approval, the Office of the Interconnection, in accordance with the Operating Agreement, Schedule 6, section 1.5.8(i), shall notify the entities that have been designated as Designated Entities for Immediate-need Projects included in the Regional Transmission Expansion Plan of such designations. Designated Entities shall accept such designations in accordance with the Operating Agreement, Schedule 6, section 1.5.8(j). In the event that (i) the Office of the Interconnection determines that no proposal resolves a posted violation or system condition; (ii) the proposing entity is not selected to be the Designated Entity; (iii) an entity does not accept the designation as a Designated Entity; or (iv) the Designated Entity fails to meet milestones that would delay the in-service date of the Immediate-need Reliability Project, the Office of the Interconnection shall develop and recommend an Immediate-need Reliability Project to solve the violation or system needs in accordance with the Operating Agreement, Schedule 6, section 1.5.8(m)(1).

(n) **Reliability Violations on Transmission Facilities Below 200 kV.** Pursuant to the expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify reliability violations on facilities below 200 kV. The Office of the Interconnection shall not post such a violation pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) unless the identified violation(s) satisfies one of the following exceptions: (i) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV that are impacted by a common contingent element, such that multiple reliability violations could be addressed by one or more solutions, including but not limited to a higher voltage solution; or (ii) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV and the Office of the Interconnection determines that given the location and electrical features of the violations one or more solutions could potentially address or reduce the flow on multiple lower voltage facilities, thereby eliminating the multiple reliability violations. If the reliability violation is identified on multiple facilities rated below 200 kV that are determined by the Office of the Interconnection to meet one of the two exceptions stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified reliability violations do not satisfy either of the two exceptions stated above, the Office of the Interconnection shall develop a solution to address the reliability violation on below 200 kV Transmission Facilities that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The Office of Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the below 200 kV reliability violations that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the below 200 kV reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such below 200 kV reliability violation will be designated to the incumbent

Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. With the exception of Immediate-need Reliability Projects under the Operating Agreement, Schedule 6, section 1.5.8(m), PJM will not select an above 200 kV solution for inclusion in the recommended plan that would address a reliability violation on a below 200 kV transmission facility without posting the violation for inclusion in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

(o) **[Reserved]**

(p) **Thermal Reliability Violations on Transmission Substation Equipment.** Pursuant to the regional transmission expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify thermal reliability violations on existing transmission substation equipment. The Office of the Interconnection shall not post such thermal reliability violations pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) if the Office of the Interconnection determines that the reliability violations would be more efficiently addressed by an upgrade to replace in kind transmission substation equipment with higher rated equipment, excluding power transmission transformers, but including station service transformers and instrument transformers. If the Office of the Interconnection determines that the reliability violation does not meet the exemption stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified thermal reliability violations satisfy the above exemption to the proposal window process, the Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the transmission substation equipment thermal reliability violations that will not be included in a proposal window pursuant to Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the transmission substation equipment thermal reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the thermal violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such transmission substation equipment thermal violations will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

1.5.9 State Agreement Approach.

(a) State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. As determined by the authorized state governmental entities, such transmission enhancements or expansions may be included in the recommended plan, either as a (i) Supplemental Project or (ii) state public policy project, which is a transmission enhancement or expansion, the costs of which will be recovered pursuant to a FERC-accepted cost allocation proposed by agreement of one or more states and voluntarily agreed to by those state(s). All costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. A state public policy project will be included in the Regional Transmission Expansion Plan for cost allocation purposes only if there is an associated FERC-accepted allocation permitting recovery of the costs of the state public policy project consistent with this Section.

(b) Subject to any designation reserved for Transmission Owners in the Operating Agreement, Schedule 6, section 1.5.8(l), the state(s) responsible for cost allocation for a Supplemental Project or a state public policy project in accordance with the Operating Agreement, Schedule 6, section 1.5.9(a) may submit to the Office of the Interconnection the entity(ies) to construct, own, operate and maintain the state public policy project from a list of entities supplied by the Office of the Interconnection that pre-qualified to be Designated Entities pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a).

1.5.10 Multi-Driver Project.

(a) When a proposal submitted by an existing Transmission Owner or Nonincumbent Developer pursuant to Operating Agreement, Schedule 6, section 1.5.8(c) meets the definition of a Multi-Driver Project and is designated to be included in the Regional Transmission Expansion Plan for purposes of cost allocation, the Office of the Interconnection shall designate the Designated Entity for the project as follows: (i) if the Multi-Driver Project does not contain a state Public Policy Requirement component, the Office of the Interconnection shall designate the Designated Entity pursuant to the criteria in the Operating Agreement, Schedule 6, section 1.5.8; or (ii) if the Multi-Driver Project contains a state Public Policy Requirement component, the Office of the Interconnection shall evaluate potential Designated Entity candidates based on the criteria in the Operating Agreement, Schedule 6, section 1.5.8, and provide its evaluation to and elicit feedback from the sponsoring state governmental entities responsible for allocation of all costs of the proposed state Public Policy Requirement component ("state governmental entity(ies)") regarding its evaluation. Based on its evaluation of the Operating Agreement, Schedule 6, section 1.5.8 criteria and consideration of the feedback from the sponsoring state governmental entity(ies), the Office of the Interconnection shall designate the Designated Entity for the Multi-Driver Project and notify such entity consistent with the Operating Agreement, Schedule 6, section 1.5.8(i). A Multi-Driver Project may be based on proposals that consist of (1) newly proposed transmission enhancements or expansions; (2) additions to, or modifications of, transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan; and/or (3) one or more transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan.

(b) A Multi-Driver Project may contain an enhancement or expansion that addresses a state Public Policy Requirement component only if it meets the requirements set forth in the

Operating Agreement, Schedule 6, section 1.5.9(a) and its cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(c) If a state governmental entity(ies) desires to include a Public Policy Requirement component after an enhancement or expansion has been included in the Regional Transmission Expansion Plan, the Office of the Interconnection may re-evaluate the relevant reliability-based enhancement or expansion, Economic-based Enhancement or Expansion, or Multi-Driver Project to determine whether adding the state-sponsored Public Policy Requirement component would create a more cost effective or efficient solution to system conditions. If the Office of the Interconnection determines that adding the state-sponsored Public Policy Requirement component to an enhancement or expansion already included in the Regional Transmission Expansion Plan would result in a more cost effective or efficient solution, the state-sponsored Public Policy Requirement component may be included in the relevant enhancement or expansion, provided all of the requirements of the Operating Agreement, Schedule 6, section 1.5.10(b) are met, and cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(d) If, subsequent to the inclusion in the Regional Transmission Expansion Plan of a Multi-Driver Project that contains a state Public Policy Requirement component, a state governmental entity(ies) withdraws its support of the Public Policy Requirement component of a Multi-Driver Project, then: (i) the Office of the Interconnection shall re-evaluate the need for the remaining components of the Multi-Driver Project without the state Public Policy Requirement component, remove the Multi-Driver Project from the Regional Transmission Expansion Plan, or replace the Multi-Driver Project with an enhancement or expansion that addresses remaining reliability or economic system needs; (ii) if the Multi-Driver Project is retained in the Regional Transmission Expansion Plan without the state Public Policy Requirement component, the costs of the remaining components will be allocated in accordance with the Tariff, Schedule 12; (iii) if more than one state is responsible for the costs apportioned to the state Public Policy Requirement component of the Multi-Driver Project, the remaining state governmental entity(ies) shall have the option to continue supporting the state Public Policy component of the Multi-Driver Project and if the remaining state governmental entity(ies) choose this option, the apportionment of the state Public Policy Requirement component will remain in place and the remaining state governmental entity(ies) shall agree upon their respective apportionments; (iv) if a Multi-Driver Project must be retained in the Regional Transmission Expansion Plan and completed with the State Public Policy component, the state Public Policy Requirement apportionment will remain in place and the withdrawing state governmental entity(ies) shall continue to be responsible for its/their share of the FERC-accepted cost allocations as filed pursuant to the Tariff, Schedule 12, section (b)(xii)(B).

(e) The actual costs of a Multi-Driver Project shall be apportioned to the different components (reliability-based enhancement or expansion, Economic-based Enhancement or Expansion and/or Public Policy Requirement) based on the initial estimated costs of the Multi-Driver Project in accordance with the methodology set forth in the Tariff, Schedule 12.

(f) The benefit metric calculation used for evaluating the market efficiency component of a Multi-Driver Project will be based on the final voltage of the Multi-Driver

Project using the Benefit/Cost Ratio calculation set forth in the Operating Agreement, Schedule 6, section 1.5.7(d) where the Cost component of the calculation is the present value of the estimated cost of the enhancement apportioned to the market efficiency component of the Multi-Driver Project for each of the first 15 years of the life of the enhancement or expansion.

(g) Except as provided to the contrary in this Operating Agreement, Schedule 6, section 1.5.10 and Operating Agreement, Schedule 6, section 1.5.8 applies to Multi-Driver Projects.

(h) The Office of the Interconnection shall determine whether a proposal(s) meets the definition of a Multi-Driver Project by identifying a more efficient or cost effective solution that uses one of the following methods: (i) combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project ("Proportional Multi-Driver Method"); or (ii) expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers ("Incremental Multi-Driver Method").

(i) In determining whether a Multi-Driver Project may be designated to more than one entity, PJM shall consider whether: (i) the project consists of separable transmission elements, which are physically discrete transmission components, such as, but not limited to, a transformer, static var compensator or definable linear segment of a transmission line, that can be designated individually to a Designated Entity to construct and own and/or finance; and (ii) each entity satisfies the criteria set forth in the Operating Agreement, Schedule 6, section 1.5.8(f). Separable transmission elements that qualify as Transmission Owner Upgrades shall be designated to the Transmission Owner in the Zone in which the facility will be located.

1.6 Approval of the Final Regional Transmission Expansion Plan.

(a) Based on the studies and analyses performed by the Office of the Interconnection under Operating Agreement, Schedule 6, the PJM Board shall approve the Regional Transmission Expansion Plan in accordance with the requirements of Operating Agreement, Schedule 6. The PJM Board shall approve the cost allocations for transmission enhancements and expansions consistent with Tariff, Schedule 12. Supplemental Projects shall be integrated into the Regional Transmission Expansion Plan approved by the PJM Board but shall not be included for cost allocation purposes.

(b) The Office of the Interconnection shall publish the current, approved Regional Transmission Expansion Plan on the PJM Internet site. Within 30 days after each occasion when the PJM Board approves a Regional Transmission Expansion Plan, or an addition to such a plan, that designates one or more Transmission Owner(s) or Designated Entity(ies) to construct such expansion or enhancement, the Office of the Interconnection shall file with FERC a report identifying the expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Operating Agreement, Schedule 6, section 1.5.6(l) to bear responsibility for the costs of the project.

(**c**) If a Regional Transmission Expansion Plan is not approved, or if the transmission service requested by any entity is not included in an approved Regional Transmission Expansion Plan, nothing herein shall limit in any way the right of any entity to seek relief pursuant to the provisions of Section 211 of the Federal Power Act.

(d) Following PJM Board approval, the final Regional Transmission Expansion Plan shall be documented, posted publicly and provided to the Applicable Regional Entities.

1.7 Obligation to Build.

(a) Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners or Designated Entities designated as the appropriate entities to construct, own and/or finance enhancements or expansions specified in the Regional Transmission Expansion Plan shall construct, own and/or finance such facilities or enter into appropriate contracts to fulfill such obligations. Except as provided in Operating Agreement, Schedule 6, section 1.5.8(k), nothing herein shall require any Transmission Owner to construct, finance or own any enhancements or expansions specified in the Regional Transmission Expansion Plan for which the plan designates an entity other than a Transmission Owner as the appropriate entity to construct, own and/or finance such enhancements or expansions.

(b) Nothing herein shall prohibit any Transmission Owner from seeking to recover the cost of enhancements or expansions on an incremental cost basis or from seeking approval of such rate treatment from any regulatory agency with jurisdiction over such rates.

(c) The Office of the Interconnection shall be obligated to collect on behalf of the Transmission Owner(s) or Designated Entity(ies) all charges established under Tariff, Schedule 12 in connection with facilities which the Office of the Interconnection designates one or more Transmission Owners or Designated Entity(ies) to build pursuant to this Regional Transmission Expansion Planning Protocol. Such charges shall compensate the Transmission Owner(s) or Designated Entity(ies) for all costs related to such RTEP facilities under a FERC-approved rate and will include any FERC-approved incentives.

(d) In the event that a Transmission Owner declines to construct an economic transmission enhancement or expansion developed under sections 1.5.6(d) and 1.5.7 of this Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the Office of the Interconnection shall promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit the FERC to determine what action, if any, it should take.

1.8 Interregional Expansions

(a) PJM shall collect from Midwest Independent System Operator, Inc., for distribution to the applicable Transmission Owners, in accordance with Schedule 12 of the PJM Tariff, revenues collected by the Midwest Independent System Operator, Inc. under the Open Access Transmission Tariff of the Midwest Independent System Owner, Inc. with respect to transmission enhancements or expansions for which the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility for transmission enhancements or expansions in the PJM Region to market participants in the region of the Midwest Independent System Operator, Inc.

(b) PJM shall disburse to the Midwest Independent System Operator, Inc., for distribution to applicable transmission owners of the Midwest Independent System Operator, Inc., revenues collected under Schedule 12 of the PJM Tariff which establishes a charge in connection with enhancements or expansions in the region of the Midwest Independent System Operator, Inc. the cost responsibility for which has been assigned to market participants in the PJM Region under the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.

(c) Nothing in this Section 1.8 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the PJM Tariff and applicable agreements.

1.9 Relationship to the PJM Open Access Transmission Tariff.

Nothing herein shall modify the rights and obligations of an Eligible Customer or a Transmission Customer with respect to required studies and completion of necessary enhancements or expansions. An Eligible Customer or Transmission Customer electing to follow the procedures in the PJM Tariff instead of the procedures provided herein, shall also be responsible for the related costs. The enhancement and expansion study process under this Protocol shall be funded as a part of the operating budget of the Office of the Interconnection.

SCHEDULE 6-A
Interregional Transmission Coordination Between the SERTP and PJM Regions

The Office of the Interconnection, through its regional transmission planning process, coordinates with the public utility transmission providers of Southeastern Regional Transmission Planning ("SERTP," and individually, "SERTP Transmission Provider," and collectively, "SERTP Transmission Providers"), as the transmission providers and planners for the SERTP region to address transmission planning coordination issues related to interregional transmission projects. The interregional transmission coordination procedures include a detailed description of the process for coordination between the SERTP Transmission Providers and the Office of the Interconnection, to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than transmission projects included in the respective regional transmission plans. The interregional transmission coordination procedures are hereby provided in this Schedule 6-A with additional materials provided on the PJM Regional Planning website.

The Office of the Interconnection and each of the SERTP Transmission Providers shall:

(1) Coordinate and share the results of the SERTP Transmission Providers' and the Office of the Interconnection's regional transmission plans to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than separate regional transmission projects;

(2) Identify and jointly evaluate transmission projects that are proposed to be located in both transmission planning regions;

(3) Exchange, at least annually, planning data and information; and

(4) Maintain a website and e-mail list for the communication of information related to the coordinated planning process.

The SERTP Transmission Providers and the Office of the Interconnection developed a mutually agreeable method for allocating between the two transmission planning regions the costs of new interregional transmission projects that are located within both transmission planning regions. Such cost allocation method satisfies the six interregional cost allocation principles set forth in Order No. 1000 and are included in Tariff, Schedule 12-B.

For purposes of this Schedule 6-A, each of the SERTP Transmission Provider's transmission planning process is the process described in each of the SERTP Transmission Providers' open access transmission tariffs; the Office of the Interconnection's regional transmission planning process is the process described in Operating Agreement, Schedule 6. References to the respective transmission planning processes in each of the SERTP Transmission Providers' open access transmission tariffs are intended to identify the activities described in those tariff provisions. References to the respective regional transmission plans in this Schedule 6-A are intended to identify, for the Office of the Interconnection, the PJM Regional Transmission Expansion Plan ("RTEP"), as defined in applicable PJM documents and, for the each SERTP Transmission Providers, the SERTP regional transmission plan which includes the applicable ten (10) year transmission expansion plan. Unless noted otherwise, section references in this Schedule 6-A refer to sections within this Schedule 6-A.

Nothing in this Schedule 6-A is intended to affect the terms of any bilateral planning or operating agreements between transmission owners and/or transmission service providers that exist as of the effective date of this Schedule 6-A or that are executed at some future date.

INTERREGIONAL TRANSMISSION PLANNING PRINCIPLES

Representatives of the SERTP and the Office of the Interconnection will meet no less than once per year to facilitate the interregional coordination procedures described below (as applicable). Representatives of the SERTP and the Office of the Interconnection may meet more frequently during the evaluation of project(s) proposed for purposes of interregional cost allocation between the SERTP and the Office of the Interconnection. For purposes of this Schedule 6-A, an "interregional transmission project" means a facility or set of facilities that would be physically located in both the SERTP and PJM regions and would interconnect to transmission facilities in both the SERTP and PJM regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan that are currently under development.

1. **Coordination**

1.1 **Review of Respective Regional Transmission Plans:** Biennially, the Office of the Interconnection and the SERTP Transmission Providers shall review each other's current regional transmission plan(s) and engage in the data exchange and joint evaluation described in sections 2 and 3 below.

> 1.1.1 The review of each region's regional transmission plan(s), which plans include the transmission needs and planned upgrades of the transmission providers in each region, shall occur on a mutually agreeable timetable, taking into account each region's transmission planning process timeline.

1.2 **Review of Proposed Interregional Transmission Projects:** The SERTP Transmission Providers and the Office of the Interconnection will also coordinate with regard to the evaluation of interregional transmission projects identified by the SERTP Transmission Providers and the Office of the Interconnection as well as interregional transmission projects proposed for Interregional Cost Allocation Purposes ("Interregional CAP"), pursuant to section 3 below and Tariff, Schedule 12-B. Initial coordination activities regarding new interregional proposals will typically begin during the third calendar quarter. The SERTP Transmission Providers and the Office of the Interconnection will exchange status updates for new interregional transmission project proposals or proposals currently under consideration as needed. These status updates will generally include, if applicable: (i) an update of the region's evaluation of the proposal; (ii) the latest calculation of Regional Benefits (as defined in Tariff, Schedule 12-B); (iii) the anticipated timeline for future assessments; and (iv) reevaluations related to the proposal.

1.3 **Coordination of Assumptions Used in Joint Evaluation:** The SERTP Transmission Providers and the Office of the Interconnection will coordinate assumptions used in joint evaluations, as necessary, which includes items such as:

1.3.1 Expected timelines/milestones associated with the joint evaluation
1.3.2 Study assumptions
1.3.3 Regional benefit calculations

1.4 **Posting of Materials on Regional Planning Websites:** The SERTP Transmission Providers and the Office of the Interconnection will coordinate with respect to the posting of materials related to the interregional coordination procedures described in this Schedule 6-A on each region's regional planning website.

2. **Data Exchange**

2.1 At least annually, each of the SERTP Transmission Providers and the Office of the Interconnection shall exchange power-flow models and associated data used in the regional transmission planning processes to develop their respective then-current regional transmission plan(s). This exchange will occur when such data is available in each of the transmission planning processes, typically during the first calendar quarter. Additional transmission-based models and data may be exchanged between the SERTP Transmission Providers and the Office of the Interconnection as necessary and if requested. For purposes of the interregional coordination activities outlined in this Schedule 6-A, only data and models used in the development of the SERTP Transmission Provider's and the Office of the Interconnection's then-current regional transmission plans and used in their respective regional transmission planning processes will be exchanged. This data will be posted on the pertinent regional transmission planning process' websites, consistent with the posting requirements of the respective regional transmission planning processes, and is considered CEII. The Office of the Interconnection shall notify the SERTP Transmission Providers of such posting.

2.2 The RTEP will be posted on the Office of the Interconnection's Regional Planning website pursuant to the Office of the Interconnection's regional transmission planning process. The Office of the Interconnection shall notify the SERTP Transmission Providers of such posting so that the SERTP Transmission Providers may retrieve these transmission plans. Each of the SERTP Transmission Providers will exchange its then-current regional plan(s) in a similar manner according to its regional transmission planning process.

3. **Joint Evaluation**

3.1 **Identification of Interregional Transmission Projects:** The SERTP Transmission Providers and the Office of the Interconnection shall exchange planning models and data and current regional transmission plans as described in section 2 above. Each SERTP Transmission Provider and the Office of the Interconnection will review one another's then-current regional transmission plan(s) in accordance with the coordination procedures described in section 1 above and their respective regional transmission planning processes. If through this review, a SERTP Transmission Provider and the Office of the Interconnection identify a potential interregional transmission project that could be more efficient or cost effective than projects included in the respective regional plans, the SERTP Transmission Provider and the Office of the Interconnection will jointly evaluate the potential project pursuant to section 3.3 below.

3.2 **Identification of Interregional Transmission Projects by Stakeholders:** Stakeholders may propose projects that may be more efficient or cost-effective than projects included in the SERTP Transmission Providers' and the Office of the Interconnection's regional transmission plans pursuant to the procedures in each region's regional transmission planning processes. The SERTP Transmission Providers and Office of the Interconnection will evaluate interregional transmission projects proposed by stakeholders pursuant to section 3.3 below.

3.3 **Evaluation of Interregional Transmission Projects:** The SERTP Transmission Providers and the Office of the Interconnection shall act through their respective regional transmission planning processes to evaluate potential interregional transmission projects and to determine whether the inclusion of any potential interregional transmission projects in each region's regional transmission plan would be more efficient or cost-effective than projects included in the respective then-current regional transmission plans. Such analysis shall be consistent with accepted planning practices of the respective regions and the methods utilized to produce each region's respective regional transmission plan(s). The Office of the Interconnection will evaluate potential interregional transmission projects consistent with Operating Agreement, Schedule 6 and the PJM Manuals 14A entitled New Services Request Process and 14B entitled PJM Region Transmission Planning Process on the PJM Website at http://www.pjm.com/documents/manuals.aspx. To the extent possible and as needed, assumptions and models will be coordinated between the SERTP Transmission Providers and the Office of the Interconnection, as described in section 1 above. Data shall be exchanged to facilitate this evaluation using the procedures described in section 2 above.

3.4 **Evaluation of Interregional Transmission Projects Proposed for Interregional Cost Allocation Purposes:** Interregional transmission projects proposed for Interregional CAP must be submitted in both the SERTP and PJM regional transmission planning processes. The project submittals must satisfy the applicable requirements for submittal of interregional transmission projects, including those in Operating Agreement, Schedule 6 and Tariff, Schedule 12-B. The submittals in the respective regional transmission planning processes must identify the project proposal as interregional in scope and identify SERTP and PJM as the regions in which the project is proposed to interconnect. The Office of the Interconnection will determine whether the submittal for the proposed interregional transmission project satisfies all applicable requirements. Upon finding that the project submittal satisfies all such applicable requirements, the Office of the Interconnection will notify the SERTP Transmission Provider. Upon both regions so notifying one another that the project is eligible for consideration pursuant to their respective regional transmission planning processes, the SERTP Transmission Provider and the Office of the Interconnection will jointly evaluate the proposed interregional projects.

3.4.1 If an interregional transmission project is proposed in the SERTP and Office of Interconnection for Interregional CAP, the initial evaluation of the project will typically begin during the third calendar quarter, with analysis conducted in the same manner as analysis of interregional projects identified pursuant to sections 3.1 and 3.2 above. Further evaluation shall also be performed pursuant to this section 3.4. Projects proposed for Interregional CAP shall also be subject to the requirements of Tariff, Schedule 12-B.

3.4.2. Each region, acting through its regional transmission planning process, will evaluate proposals to determine whether the interregional transmission project(s) proposed for Interregional CAP addresses transmission needs that are currently being addressed with projects in its regional transmission plan(s) and, if so, which projects in the regional transmission plan(s) could be displaced by the proposed project(s).

3.4.3. Based upon its evaluation, each region will quantify a Regional Benefit based upon the transmission costs that each region is projected to avoid due to its transmission projects being displaced by the proposed project. For purposes of this Schedule 6-A, "Regional Benefit" means: (i) for the SERTP Transmission Providers, the total avoided costs of projects included in the then-current regional transmission plan that would be displaced if the proposed interregional transmission project was included and (ii) for the Office of the Interconnection, the total avoided costs of projects included in the then-current regional transmission plan that would be displaced if the proposed interregional transmission project was included. The Regional Benefit is not necessarily the same as the benefits used for purposes of regional cost allocation.

3.5 **Inclusion of Interregional Projects Proposed for Interregional CAP in Regional Transmission Plans:** An interregional transmission project proposed for Interregional CAP in the SERTP and Office of the Interconnection will be included in the respective regional plans for purposes of cost allocation only after it has been selected by both the SERTP and Office of the Interconnection regional processes to be included in their respective regional plans for purposes of cost allocation.

3.5.1. To be selected in both the SERTP and Office of the Interconnection regional plans for purposes of cost allocation means that each region has performed all evaluations, as prescribed in its regional transmission planning processes, necessary for a project to be included in its regional transmission plans for purposes of cost allocation.

- For SERTP: All requisite approvals are obtained, as prescribed in the SERTP regional transmission planning process, necessary for a project to be included in the SERTP regional transmission plan for purposes of cost allocation. This includes any requisite regional benefit to cost ("BTC") ratio calculations performed pursuant to the respective regional transmission planning processes. For purposes of the SERTP, the anticipated allocation of costs of the interregional transmission project for use in the regional BTC ratio calculation shall be based upon the ratio of the SERTP's Regional Benefit to the sum of the Regional Benefits identified for both the SERTP and the Office of the Interconnection; and

- For the Office of Interconnection: All requisite approvals are obtained, as prescribed in the PJM regional transmission planning process, necessary for a project to be included in the RTEP for purposes of cost allocation.

3.6 **Removal from Regional Plans:** An interregional transmission project may be removed from the SERTP's or Office of the Interconnection's regional plan for purposes of cost allocation: (i) if the developer fails to meet developmental milestones; (ii) pursuant to the reevaluation procedures specified in the respective regional transmission planning processes; or (iii) if the project is removed from one of the region's regional transmission plan(s) pursuant to the requirements of its regional transmission planning process.

3.6.1 The Office of the Interconnection, shall notify the SERTP Transmission Provider if an interregional project or a portion thereof is likely to be removed from its regional transmission plan.

4. **Transparency**

4.1 The Office of the Interconnection shall post procedures for coordination and joint evaluation on the Regional Planning website.

4.2 Access to the data utilized will be made available through the Regional Planning website subject to the appropriate clearance, as applicable (such as CEII and confidential non-CEII). Both planning regions will make available, on their respective regional websites, links to where stakeholders can register (if applicable/available) for the stakeholder committees or distribution lists of the other planning region.

4.3 PJM will provide status updates of SERTP interregional activities to the TEAC including:

- Facilities to be evaluated
- Analysis performed
- Determinations/results.

4.4 Stakeholders will have an opportunity to provide input and feedback within the respective regional planning processes of SERTP and the Office of the Interconnection related to interregional facilities identified, analysis performed, and any determination/results. Stakeholders may participate in either or both regions' regional planning processes to provide their input and feedback regarding the interregional coordination between the SERTP and the Office of the Interconnection.

4.5 The Office of the Interconnection will post a list on the Regional Planning Website of interregional transmission projects proposed for purposes of cost allocation in both the SERTP and PJM that are not eligible for consideration because they do not satisfy the regional project threshold criteria of one or both of the regions as well as post an explanation of the thresholds the proposed interregional project failed to satisfy.

SCHEDULE 6-B
Interregional Transmission Coordination Between PJM, New York Independent System Operator, Inc. and ISO New England Inc.

PJM, its Transmission Owners, and any other interested parties shall coordinate system planning activities with neighboring planning regions, (*i.e.*, New York Independent System Operator, Inc. and ISO New England Inc.) ("ISO/RTO Regions") pursuant to the Northeastern Planning Protocol ("Protocol") identified in Operating Agreement, Schedule 6, section 1.5.5(b).

The Interregional Planning Protocol includes a description of the committee structure, processes, and procedures through which system planning activities are openly and transparently coordinated by the ISO/RTO Regions. The objective of the interregional planning process is to contribute to the on-going reliability and the enhanced operational and economic performance of the ISO/RTO Regions through: (i) exchange of relevant data and information; (ii) coordination of procedures to evaluate certain interconnection and transmission service requests; (iii) periodic comprehensive interregional assessments; (iv) identification and evaluation of potential Interregional Transmission Projects that can address regional needs in a manner that may be more efficient or cost-effective than separate regional solutions, in accordance with the requirements of Order No. 1000.

Section 9 of the Protocol indicates that the cost allocation for identified interregional transmission projects between PJM and NYISO shall be conducted in accordance with the Joint Operating Agreement Among and Between New York Independent System Operator, Inc. and PJM Interconnection, L.L.C. referenced in Operating Agreement, Schedule 6, section 1.5.5(b).

The planning activities of the ISO/RTO Regions shall be conducted consistent with the planning criteria of each ISO/RTO Region. The ISO/RTO Regions shall periodically produce a Northeastern Coordinated System Plan that integrates the system plans of all of the ISO/RTO Regions.

SCHEDULE 7 -
UNDERFREQUENCY RELAY OBLIGATIONS AND CHARGES

1. UNDERFREQUENCY RELAY OBLIGATION

1.1 Application.

The obligations of this Schedule apply to each Member that is an Electric Distributor, whether or not that Member participates in the Electric Distributor sector on the Members Committee or meets the eligibility requirements for any other sector of the Members Committee.

1.1A Counterparty.

PJMSettlement is the Counterparty to obligations and all payments and distributions associated with underfrequency relay obligations and charges pursuant to this Schedule 7.

1.2 Obligations.

(a) Each Electric Distributor in the PJM Mid-Atlantic Region shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 58.9 Hz and 58.5 Hz. Upon the request of the Members Committee, each Electric Distributor in the PJM Mid-Atlantic Region shall document that it has complied with the requirement for underfrequency load shedding relays.

(b) Each Electric Distributor in the PJM West Region shall install or contractually arrange for underfrequency relays to interrupt at least 25 percent of its peak load with 5 percent of the load interrupted at each of five frequency levels: 59.5 Hz, 59.3 Hz, 59.1 Hz, 58.9 Hz, and 58.7 Hz; provided, however, that each Electric Distributor in the Commonwealth Edison Company Zone shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 59.0 Hz, and 58.7 Hz. Additionally, provided, however, that each Electric Distributor in the East Kentucky Power Cooperative Zone shall install or contractually arrange for underfrequency relays to meet requirements in the currently effective SERC underfequency load shedding regional reliability standard, to interrupt 30 percent of its peak load including allowable tolerances identified in the SERC underfrequency load shedding regional reliability standard, with 5 percent of its peak load including allowable tolerances identified in the SERC underfrequency load shedding regional reliability standard at each of the frequency levels: 59.5 Hz, 59.3 Hz, 59.1 Hz, 58.9 Hz, 58.7 Hz and 58.5 Hz. Upon the request of the Markets and Reliability Committee established by the Reliability Assurance Agreement, each Electric Distributor in the PJM West Region shall document that it has complied with the requirement for underfrequency load shedding relays.

(c) Each Electric Distributor in the PJM South Region shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of 3 frequency levels: 59.3 Hz, 59.0 Hz, 58.5 Hz. Upon the request of the Markets and Reliability Committee established by the Reliability Assurance Agreement, each Electric Distributor in the PJM South Region shall document that it has complied with the requirement for underfrequency load shedding relays.

2. UNDERFREQUENCY RELAY CHARGES

If an Electric Distributor is determined to not have the required underfrequency relays, it shall pay an underfrequency relay charge of:

Charge = D x R x 365

where

D = the amount, in megawatts, the Electric Distributor is deficient; and

R = the daily rate per megawatt, which shall be based on the annual carrying charges for a new combustion turbine generator, installed and connected to the transmission system, which daily deficiency rate as of the Effective Date shall be $58.400/per kilowatt-year or $160 per megawatt-day.

3. DISTRIBUTION OF UNDERFREQUENCY RELAY CHARGES

3.1 Share of Charges.

Each Electric Distributor that has complied with the requirements for underfrequency relays imposed by this Agreement during a Planning Period, without incurring an underfrequency relay charge, shall share in any underfrequency relay charges paid by any other Electric Distributor that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the number of megawatts of a Electric Distributor's load in the most recently completed month at the time of the peak for the PJM Region during that month rounded to the next higher whole megawatt, as established initially on the Effective Date and as updated at the beginning of each month thereafter.

3.2 Allocation by the Office of the Interconnection.

In the event all of the Electric Distributors have incurred underfrequency relay charges during a Planning Period, the underfrequency relay charges shall be distributed among the Electric Distributors on an equitable basis as determined by the Office of the Interconnection.

SCHEDULE 8 -
DELEGATION OF PJM REGION RELIABILITY RESPONSIBILITIES

1. DELEGATION

The following responsibilities shall be delegated to the Office of the Interconnection by the parties to the Reliability Assurance Agreement.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Reliability Assurance Agreement; and

(b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT

With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners or providers of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

(c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional

Reliability Council principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 9

[Reserved for Future Use]

SCHEDULE 10 -
FORM OF NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the "Agreement") is made this ___ day of ___________, 20__, by and between ____________________, an Authorized Person, as defined below, and PJM Interconnection, L.L.C., a Delaware limited liability company, with offices at 2750 Monroe Blvd., Audubon, PA 19403 ("PJM"). The Authorized Person and PJM shall be referred to herein individually as a "Party," or collectively as the "Parties."

RECITALS

Whereas, PJM serves as the Regional Transmission Organization with reliability and/or functional control responsibilities over transmission systems involving fourteen states including the District of Columbia, and operates and oversees wholesale markets for electricity pursuant to the requirements of the PJM Tariff and the Operating Agreement, as defined below; and

Whereas, the Market Monitoring Unit serves as the monitor for PJM's wholesale markets for electricity, and

Whereas, the Operating Agreement requires that PJM and the Market Monitoring Unit maintain the confidentiality of Confidential Information; and

Whereas, the Operating Agreement requires PJM and the Market Monitoring Unit to disclose Confidential Information to Authorized Persons upon satisfaction of conditions stated in the Operating Agreement, which may include, but are not limited to, the execution of this Agreement by the Authorized Person and the maintenance of the confidentiality of such information pursuant to the terms of this Agreement; and

Whereas, PJM desires to provide Authorized Persons with the broadest possible access to Confidential Information, consistent with PJM's and the Market Monitoring Unit's obligations and duties under the PJM Operating Agreement, the PJM Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the Operating Agreement, whereby PJM or the Market Monitoring Unit may provide Confidential Information to the Authorized Person.

NOW, THEREFORE, **intending to be legally bound, the Parties hereby agree as follows:**

1. Definitions.

1.1 Affected Member.

A Member of PJM which as a result of its participation in PJM's markets or its membership in PJM provided Confidential Information to PJM, which Confidential Information is requested by, or is disclosed to an Authorized Person under this Agreement.

1.2 Authorized Commission.

(i) A State (which shall include the District of Columbia) public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

1.3 Authorized Person.

A person, including the undersigned, which has executed this Agreement and is authorized in writing by an Authorized Commission to receive and discuss Confidential Information. Authorized Persons may include attorneys representing an Authorized Commission or consultants and/or contractors directly employed or retained by an Authorized Commission, provided however that consultants or contractors may not initiate requests for Confidential Information from PJM or the Market Monitoring Unit.

1.4 Confidential Information.

Any information that would be considered non-public or confidential under the Operating Agreement.

1.5 FERC.

The Federal Energy Regulatory Commission.

1.6 Information Request.

A written request, in accordance with the terms of this Agreement for disclosure of Confidential Information pursuant to Operating Agreement, section 18.17.4.

1.7 Operating Agreement.

The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., as it may be further amended or restated from time to time.

1.8 Market Monitoring Unit.

The Market Monitoring Unit established under Tariff, Attachment M.

1.9 PJM Tariff.

The PJM Open Access Transmission Tariff, as it may be amended from time to time.

1.10 Third Party Request.

Any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose.

The Authorized Person represents and warrants that he or she: (i) is presently an Authorized Person as defined herein; (ii) is duly authorized to enter into and perform this Agreement; (iii) has adequate procedures to protect against the release of Confidential Information, and (iv) is familiar with, and will comply with, all such applicable Authorized Commission procedures. The Authorized Person hereby covenants and agrees on behalf of himself or herself to deny any Third Party Request and defend against any legal process which seeks the release of Confidential Information in contravention of the terms of this Agreement.

2.2 Discussion of Confidential Information with Other Authorized Persons.

The Authorized Person may discuss Confidential Information with employees of the Authorized Commission who have been designated Authorized Persons pursuant to the Operating Agreement and with such other third-party. Authorized Persons who have executed non-disclosure agreements with PJM containing the same terms and conditions as this Agreement.

2.3 Defense Against Third Party Requests.

The Authorized Person shall defend against any disclosure of Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, seeking to obtain any necessary protective orders. The Authorized Person shall provide PJM, and PJM shall provide each Affected Member, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Person agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM (and of which PJM shall, in turn, advise any Affected Members) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

2.4 Care and Use of Confidential Information.

2.4.1 Control of Confidential Information.

The Authorized Person(s) shall be the custodian(s) of any and all Confidential Information received pursuant to the terms of this Agreement from PJM or the Market Monitoring Unit.

2.4.2 Access to Confidential Information.

The Authorized Person shall ensure that Confidential Information received by that Authorized Person is disseminated only to those persons publicly identified as Authorized Persons on Exhibit "A" to the certification provided by the State Commission to PJM pursuant to the procedures contained in Operating Agreement, section 18.17.4.

2.4.3 Schedule of Authorized Persons.

(i) The Authorized Person shall promptly notify PJM and the Market Monitoring Unit of any change that would affect the Authorized Person's status as an Authorized Person, and in such event shall request, in writing, deletion from the schedule referred to in section (ii), below.

(ii) PJM shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on the PJM website and/or by written request. Such schedule shall be compiled by PJM, based on information provided by any Authorized Person and/or Authorized Commission. PJM shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by PJM in the compilation and/or maintenance of the schedule.

2.4.4 Use of Confidential Information.

The Authorized Person shall use the Confidential Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting and generation planning and siting materially affecting retail customers within the State, and for no other purpose.

2.4.5 Return of Confidential Information.

Upon completion of the inquiry or investigation referred to in the Information Request, or for any reason the Authorized Person is, or will no longer be an Authorized Person, the Authorized Person shall (a) return the Confidential Information and all copies thereof to PJM and/or the Market Monitoring Unit, or (b) provide a certification that the Authorized Person has destroyed all paper copies and deleted all electronic copies of the Confidential Information. PJM and/or the Market Monitoring Unit, as applicable, may waive this condition in writing if such Confidential Information has become publicly available or non-confidential in the course of business or pursuant to the PJM Tariff, PJM rule or order of the FERC.

2.4.6 Notice of Disclosures.

The Authorized Person, directly or through the Authorized Commission, shall promptly notify PJM and/or the Market Monitoring Unit, and PJM and/or the Market Monitoring Unit shall promptly notify any Affected Member, of any inadvertent or intentional release or possible release of the Confidential Information provided pursuant to this Agreement. The Authorized Person shall take all steps to minimize any further release of Confidential Information, and shall take reasonable steps to attempt to retrieve any Confidential Information that may have been released.

2.5 Ownership and Privilege.

Nothing in this Agreement, or incident to the provision of Confidential Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM and/or the Market Monitoring Unit, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM, the Market Monitoring Unit (to the extent that it owns any intellectual property), and/or the Affected Member.

3. Remedies.

3.1 Material Breach.

The Authorized Person agrees that release of Confidential Information to persons not authorized to receive it constitutes a breach of this Agreement and may cause irreparable harm to PJM and/or the Affected Member. In the event of a breach of this Agreement by the Authorized Person, PJM shall terminate this Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person hereunder shall thereupon terminate; provided, however, that PJM may restore an individual's status as an Authorized Person after consulting with the Affected Member and to the extent that: (i) PJM determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Member; or (iii) similar good cause shown. Any appeal of PJM's actions under this section shall be to FERC.

3.2 Judicial Recourse.

In the event of any breach of this Agreement, PJM and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Information to PJM. The Authorized Person expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Information to PJM.

3.3 Waiver of Monetary Damages.

No Authorized Person shall have responsibility or liability whatsoever under this Agreement for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of, or in connection with, the release of Confidential Information to persons not authorized to receive it. Nothing in this Section 3.3 is intended to limit the liability of any person who is not under contract to provide services to an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

4. Jurisdiction.

The Parties agree that (i) any dispute or conflict requesting the relief in Operating Agreement, Schedule 10, section 3.1 and Operating Agreement, Schedule 10, section 3.2(a) shall be submitted to FERC for hearing and resolution; (ii) any dispute or conflict requesting the relief in Operating Agreement, Schedule 10, section 3.2(c) may be submitted to FERC or any court of competent jurisdiction for hearing and resolution; and (iii) jurisdiction over all other actions and requested relief shall lie in any court of competent jurisdiction.

5. Notices.

All notices required pursuant to the terms of this Agreement shall be in writing, and served upon the following individuals in person, or at the following addresses or email addresses:

If to the Authorized Person:

____
____
____
____
(email address)

with a copy to

____
____
____
____
(email address)

If to PJM:

General Counsel
2750 Monroe Blvd.
Audubon, PA 19403
GeneralCounsel@pjm.com

If to the Market Monitoring Unit:

Monitoring Analytics, LLC
[address and contact information]

6. Severability and Survival.

In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Operating Agreement, the terms of the Operating Agreement shall in all events be controlling. The Authorized Person acknowledges that any and all obligations of the Authorized Person hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Person and their respective Authorized Commission.

7. Representations.

The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

8. Third Party Beneficiaries.

The Parties specifically agree and acknowledge that each Member as defined in the Operating Agreement is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

9. Counterparts.

This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

10. Amendment.

This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

PJM INTERCONNECTION, L.L.C.	**AUTHORIZED PERSON**
By:	By:
_____________________________	_____________________________
Name:	Name:
Title:	Title:

SCHEDULE 10A -
FORM OF CERTIFICATION

This Certification (the "Certification") is given this ___day of ____________, 200_, by _______________________________, a _______________________ (the "Authorized Commission"), to and for the benefit of PJM Interconnection, LLC ("PJM") and its Members. The Authorized Commission and PJM shall be referred to herein collectively as the "Parties".

Whereas, the Authorized Commission has designated the individuals on attached Exhibit "A" (the "Authorized Persons") to receive Confidential Information from PJM and/or the Market Monitoring Unit, such Exhibit A to be updated from time to time, and

Whereas, as a condition precedent to the provision of Confidential Information to the Authorized Persons, the Authorized Commission is required to make certain representations and warranties to PJM, and

Whereas, PJM and/or the Market Monitoring Unit will provide Confidential Information to the Authorized Commission subject to the terms of this Certification; and

Whereas, the Parties desire to set forth those representations and warranties herein.

Now, therefore, the Authorized Commission hereby makes the following representations and warranties, all of which shall be true and correct as of the date of execution of this Certification, and at all times thereafter, and with the express understanding that PJM, the Market Monitoring Unit, and any Affected Member shall rely on each representation and/or warranty:

1. Definitions.

Terms contained, but not defined, herein shall have the definitions or meanings ascribed to such terms in the Operating Agreement.

2. Requisite Authority.

a. The Authorized Commission hereby certifies that it has all necessary legal authority to execute, deliver, and perform the obligations in this Certification.

b. The Authorized Persons have, through all necessary action of the Authorized Commission, been appointed and directed by the Authorized Commission to receive Confidential Information on the Authorized Commission's behalf and for its benefit.

c. The Authorized Commission will, at all times after the provision of Confidential Information to the Authorized Persons, provide PJM with: (i) written notice of any changes in any Authorized Person's qualification as an Authorized Person within two (2) Business Days of such change; (ii) written confirmation to any inquiry by PJM regarding the status or identification of any specific Authorized Person within two (2) Business Days of such request, and (iii) periodic written updates, no less often than semi-annually, containing the names of all Authorized Persons appointed by the Authorized Commission.

3. Protection of Confidential Information.

a. The Authorized Commission has adequate internal procedures, to protect against the release of any Confidential Information by the Authorized Persons or other employee or agent of the Authorized Commission, and the Authorized Commission and the Authorized Persons will strictly enforce and periodically review all such procedures.

b. The Authorized Commission has legal authority to protect the confidentiality of Confidential Information from public release or disclosure and/or from release or disclosure to any other person or entity, either by the Authorized Commission or the Authorized Persons, as agents of the Authorized Commission.

c. The Authorized Commission shall ensure that Confidential Information shall be maintained by, and accessible only to, the Authorized Persons.

4. Defense Against Requests for Disclosure.

The Authorized Commission shall, unless precluded from doing so by law, use reasonable efforts to defend against, and direct Authorized Persons to defend against, disclosure of any Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Commission shall provide PJM and/or the Market Monitoring Unit with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM, the Market Monitoring Unit, and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Commission agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM and/or the Market Monitoring Unit (and of which PJM and/or the Market Monitoring Unit shall, in turn, advise any Affected Member) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

5. Use and Destruction of Confidential Information.

a. The Authorized Commission shall use, and allow the use of, the Confidential Information solely for the purpose of discharging its legal responsibility to examine and evaluate wholesale and retail electricity markets, operations, transmission planning and siting and generation planning and siting materially affecting retail customers within their respective State, and for no other purpose.

b. Upon completion of the inquiry or investigation referred to in any Information Request initiated by or on behalf of the Authorized Commission, or for any reason any Authorized Person is, or will no longer be an Authorized Person, the Authorized Commission will ensure that such Authorized Person either (a) returns the Confidential Information and all copies thereof to PJM and/or the Market Monitoring Unit, or (b) provides a certification that the Authorized Person and/or the Authorized Commission (i) has destroyed all paper copies and deleted all electronic copies of the Confidential Information or (ii) that any information required by any provision of state law to be retained will continue to be protected from disclosure.

6. Notice of Disclosure of Confidential Information.

The State Commission shall promptly notify PJM and/or the Market Monitoring Unit of any inadvertent or intentional release or possible release of the Confidential Information provided to any Authorized Person, and shall take all available steps to minimize any further release of Confidential Information and/or retrieve any Confidential Information that may have been released.

7. Release of Claims.

PJM and the Market Monitoring Unit shall be expressly entitled to rely upon any Authorized Commission Certification, in providing Confidential Information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature due to the ineffectiveness or inaccuracies of such orders, or the inaccuracy of such certification of counsel, or PJM or the Market Monitoring Unit's reliance on such orders, and the Authorized Commission hereby waives any such claim, now or in the future, whether known or unknown.

8. Ownership and Privilege.

Nothing in this Certification, or incident to the provision of Confidential Information to the Authorized Commission pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM and/or the Market Monitoring Unit, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM, the Market Monitoring Unit, and/or the Affected Member.

Executed, as of the date first set out above.

[Commission]

By:___________________________
Its:___________________________

SEE NEXT PAGE

EXHIBIT A –
CERTIFICATION
LIST OF AUTHORIZED PERSONS

Name	Mailing Address	Email	Tel #	Scope and Duration of Authority

SCHEDULE 11 -
ALLOCATION OF COSTS ASSOCIATED WITH NERC PENALTY ASSESSMENTS

References to section numbers in this Schedule 11 refer to sections of this Schedule 11, unless otherwise specified.

1.1 Purpose and Objectives.

Under the NERC Functional Model and the NERC Rules of Procedure, Registered Entities within a specific function may be assessed penalties by NERC for violations of NERC Reliability Standards. Pursuant to the terms and conditions of the PJM Governing Agreements, certain tasks associated with Reliability Standards compliance may be performed either by PJM Interconnection, L.L.C. ("PJM") and/or the Members even when they are not the Registered Entity. This Schedule furnishes a mechanism by which either PJM or a Member may directly allocate monetary penalties imposed by NERC on the Registered Entity to the entity or entities whose conduct is determined by NERC to have lead to a Reliability Standards violation. The purpose of this schedule is to allow for cost allocation; nothing in this schedule is intended to affect the obligations of the Registered Entity for compliance with NERC Reliability Standards.

1.2 [Reserved for Future Use]

1.3 Allocation of Costs When PJM is the Registered Entity

(a) If NERC assesses a monetary penalty against PJM as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of a Member or Members contributed to the Reliability Standard violation(s) at issue, then PJM may directly allocate such penalty costs or a portion thereof to the Member or Members whose conduct contributed to the Reliability Standards violation(s), provided that all of the following conditions have been satisfied:

(1) The Member or Members received notice and an opportunity to fully participate in the underlying Compliance Monitoring and Enforcement Program proceeding;

(2) This Compliance Monitoring and Enforcement Program proceeding produced a finding, subsequently filed with FERC, that the Member contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

(3) A root cause finding by NERC filed with the FERC identifying the Member's or Members' conduct as causing or contributing to the Reliability Standards violation charged against PJM as the Registered Entity.

(b) PJM will notify the Member or Members found to have contributed to a violation, either in whole or in part, in the Compliance Monitoring and Enforcement Program. Such notification shall set forth in writing PJM's intent to invoke this section 1.3 and directly assign the costs associated with a monetary penalty to the Member or Members and the underlying factual basis supporting a penalty cost assignment including the conduct contributing to the violation and the violations of the PJM Governing Agreement assigned tasks leading to the issuance of a penalty against the Registered Entity.

(c) A failure by a Member or Members to participate in the Compliance Monitoring and Enforcement Program proceedings will not prevent PJM from directly assigning the costs associated with a monetary penalty to the responsible Member or Members provided all other conditions set forth herein have been satisfied.

(d) PJM shall notify the Members or Members that PJM believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied.

(e) Where the Regional Entity's and/or NERC's root cause finds that more than one party's conduct contributed to the Reliability Standards violation(s), PJM shall inform all involved Members and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with such NERC's root cause analysis.

(f) Should Member or Members disagree with PJM regarding PJM's initial apportionment of the fault, the Dispute Resolution Procedures in Operating Agreement, section 5 shall not apply, but the parties' senior management shall first meet in an attempt to informally resolve the issue. If the disagreement cannot be resolved informally within ten (10) Business Days (or such other deadline as mutually agreed) then the following provisions shall apply:

(i) If an involved Member so elects, an informal non-binding proceeding shall be conducted within 30 days before a dispute resolution board consisting of officers of two (2) PJM Members who are not parties to the dispute and who are selected by a random drawing of names from the pool of available PJM Members and one (1) member of the PJM Board of Managers. Such dispute resolution board shall decide on the procedures to be used for the proceeding. The final recommendation of the dispute resolution board shall be made in private session within three (3) Business Days of the termination of the proceeding. The recommendation of the dispute resolution board shall be made by simple majority vote. The dispute resolution board may, but shall not be required to, provide a written basis for its recommendation; or

(ii) If an involved Member selects not to participate in the informal non-binding proceeding, then the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act. In the FERC proceeding, the involved Member shall request that FERC determine how the costs associated with the monetary penalty should be allocated. However, if there are multiple involved Members, and if any one of them desires a proceeding described in section 1.3(f)(i) above, such proceeding shall first be conducted with respect to the Member(s) desiring such a proceeding.

(g) If PJM and the involved Member(s) agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

(h) Notwithstanding anything to the contrary contained herein, if the Member or Members fail to pay their share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.3(b) above, and the FERC issues a final order or orders which supports the NERC's root cause findings regarding the Member's or Members' conduct causing or contributing to the violation and PJM's initial determinations in paragraph 1.3(f) above, such payment shall be due with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Registered Entity. Provided, however, if the Member or Members pays their share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.3(b) above, and the FERC issues a final order or orders which does not support the NERC's root cause findings regarding the Member's or Members' conduct causing or contributing to the violation and PJM's initial determinations in paragraph 1.3(f) above, such payment shall be refunded in full with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Member or Members.

1.4 Allocation of Costs When a PJM Member is the Registered Entity

(a) If NERC assesses a monetary penalty against a Member as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of PJM contributed to the Reliability Standard violation(s) at issue, then such Member may directly allocate such penalty costs or portion thereof to PJM to the extent PJM's conduct contributed to the Reliability Standards violation(s), provided that the following conditions have been satisfied:

(1) PJM received notice and an opportunity to fully participate in the underlying Compliance Monitoring and Enforcement Program proceeding;

(2) This Compliance Monitoring and Enforcement Program proceeding produced a finding, subsequently filed with FERC, that PJM contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

(3) A root cause finding by NERC has been filed at the FERC identifying PJM's conduct as causing or contributing to the Reliability Standards violation charged against the Member as the Registered Entity.

(b) The Member shall notify PJM if PJM is found to have contributed to a violation, either in whole or in part in the Compliance Monitoring and Enforcement Program. Such notification shall set forth in writing the Member's intent to invoke this section 1.4 and directly assign the costs associated with a monetary penalty to PJM and the underlying factual basis supporting a penalty cost assignment including the conduct contributing to the violation and the violations of the PJM Governing Agreement assigned tasks leading to the issuance of a penalty against the Registered Entity.

(c) A failure by PJM to participate in the Compliance Monitoring and Enforcement Program proceedings will not prevent the Member from directly assigning the costs associated with a monetary penalty to PJM provided all other conditions set forth herein have been satisfied.

(d) The Member shall notify PJM that the Member believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied.

(e) Where the Regional Entity's and/or NERC's root cause analysis finds more than one party's conduct contributed to the Reliability Standards violation(s), the Member shall inform PJM and make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to PJM's relative fault consistent with such root cause analysis.

(f) Should PJM disagree with the Member regarding the Member's initial apportionment of the fault, the Dispute Resolution Procedures in Operating Agreement, Schedule 5 shall not apply, but the parties' senior management shall first meet in an attempt to informally resolve the issue. If the disagreement cannot be resolved informally within ten (10)

Business Days (or other such deadline as mutually agreed) then the following provisions shall apply:

i. If PJM so elects, an informal non-binding proceeding shall be conducted within 30 days before a dispute resolution board consisting of officers of two (2) PJM Members who are not parties to the dispute and who are selected by a random drawing of names from the pool of available PJM Members and one (1) member of the PJM Board of Managers. Such dispute resolution board shall decide on the procedures to be used for the proceeding. The final recommendation of the dispute resolution board shall be made in private session within three (3) Business Days of the termination of the proceeding. The recommendation of the dispute resolution board shall be made by simple majority vote. The dispute resolution board may, but shall not be required to, provide a written basis for its recommendation; or

ii. If PJM selects not to participate in the informal non-binding proceeding, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act. In the FERC proceeding, PJM shall request that the FERC determine how the costs associated with the monetary penalty should be assigned.

(g) If the PJM and the involved Member(s) agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

(h) Notwithstanding anything to the contrary contained herein, if PJM fails to pay its share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.4(b) above, and the FERC issues a final order or orders which supports the NERC's root cause findings regarding PJM's conduct causing or contributing to the violation and the Member's initial determinations in paragraph 1.4(f) above, such payment shall be due with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Registered Entity. Provided, however, if PJM pays its share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.4(b) above, and the FERC issues a final order or orders which does not support the NERC's root cause findings regarding PJM's conduct causing or contributing to the violation and the Member's initial determinations in paragraph 1.4(f) above, such payment shall be refunded in full with interest calculated at the FERC authorized rate from the date of payment of the penalty by PJM.

1.5

Any and all costs associated with the imposition of NERC Reliability Standards penalties that may be assessed against PJM either directly by NERC or allocated by a Member or Members under this Schedule shall be (i) paid by PJM notwithstanding the limitation of liability provisions in Section 16 of the Operating Agreement; and (ii) recovered as set forth in Schedule 9 of the PJM Tariff, or as otherwise approved by the FERC.

SCHEDULE 12 -
PJM MEMBER LIST

7 Bridges Solar, LLC
AC Energy, LLC
Acciona Energy North America Corporation (AENAC)
ACT Commodities Inc.
Advanced Energy Economy Inc.
AEP Appalachian Transmission Company, Inc.
AEP Energy Partners, Inc.
AEP Energy, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Energy Storage, LLC
AES ES Holdings, LLC
Aesir Power, LLC
AES Integrated Energy, LLC
AES Laurel Mountain, LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
AEUG Madison Solar, LLC
Affirmed Energy LLC
Aggressive Energy LLC
Agile Energy Trading LLC
Agway Energy Services, LLC
Air Products & Chemicals, Inc.
Alabama Power Company
Alameda Solar I, LLC
Alegria Fund, LP
Algonquin Energy Services, Inc.
All American Power and Gas, LLC
All Choice Energy MidAmerica LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alliant Energy Resources, LLC
Alpaca Energy LLC
Alpha Gas and Electric, LLC
Alphataraxia Palladium LLC
Alternative Transmission Inc.
Altop Energy Trading LLC
Altop Energy Trading MidAtlantic LLC

Altrock LLC
Altro Power LLC
Altus Power, Inc.
Amazand, LLC
Amazon Energy LLC
Ambit Northeast, LLC
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems Inc.
Ames Energy, LLC
AMP Transmission, LLC
Anbaric Development Partners, LLC
AM Trading Solutions, LLC
AP Gas & Electric (IL), LLC
AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Apogee Energy Trading LLC
Appalachian Power Company
Appian Way Energy Partners MidAtlantic, LLC
Approved Energy II LLC
Aquenergy Systems LLC
Archer Energy, LLC
Armada Power, LLC
Armenia Mountain Wind, LLC
Aspen Generating, LLC
Aspen Gen Funding, LLC
Aspire Power Ventures, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
ATNV Energy, LP
Aurora Energy Research LLC
Automated Algorithms, LLC
Avangrid Networks, Inc.
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company

Baltimore Power Company LLC
Bancroft Energy LLC
Barclays Capital Services Corporation
Bath County Energy, LLC
Battery Utility of Ohio, LLC
Bazinga, LLC
Beaver Dam Energy LLC
Beech Ridge Energy LLC
Beech Ridge Energy II LLC
Beech Ridge Energy Storage LLC
Bellflower Solar 1, LLC
Bernards Solar, LLC
BIF II Safe Harbor Holding LLC
BIF III Holtwood LLC
Big Bend Trading, LLC
Big Level Wind LLC
Big Plain Solar, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Birchwood Power Partners, L.P.
Birdsboro Power LLC
Bishop Hill Energy LLC
BITH Solar I, LLC
Bitter Ridge Wind Farm, LLC
BJ Energy, LLC
Black Oak Capital, LLC
Blackout Power Trading Inc.
Black Rock Wind Force, LLC
Blackstone Wind Farm II, LLC
Blackstone Wind Farm, LLC
Blooming Grove Wind Energy Center LLC
Blossom Solar, LLC
Blue Harvest Solar Park LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania

Borough of Seaside Heights
Borough of South River, New Jersey
Boston Energy Group, Inc.
Boston Energy Trading and Marketing LLC
Bowfin KeyCon Energy, LLC
Bowfin KeyCon Power, LLC
BP Energy Company
BP Energy Retail Company LLC
BP Energy Holding Company LLC
Brandon Shores LLC
BREG Aggregator LLC
Brick Standard LLC
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Brookfield Renewable Trading and Marketing LP
Bruce Power Inc.
Brunner Island, LLC
Buckeye Power, Inc.
C4GT LLC
Caden Energix Axton LLC
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Energy Solutions, LLC
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, LLC
Cambria Wind LLC
Camden Plant Holding, L.L.C.
Camden Solar LLC
Camp Grove Wind Farm, LLC
Capacity Markets Partners, LLC
Cape May County Municipal Utilities Authority
Carolina Power Partners, LLC
Carroll County Energy LLC
Castleton Commodities Merchant Trading L.P.
Catalyst Power & Gas LLC
CCI U.S. Power Trading LLC
Central Electric Power Cooperative, Inc.
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC
Chesapeake Transmission LLC
Chief Conemaugh Power, LLC

Chief Conemaugh Power II, LLC
Chief Keystone Power, LLC
Chief Keystone Power II, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Cinnamon Bay, LLC
Citadel FNGE Ltd.
Citigroup Energy Inc.
Citizens' Electric Company of Lewisburg, PA
City of Batavia, Illinois
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of Rochelle
City Power & Gas, LLC
CleanChoice Energy, Inc.
Clean Energy Future – Lordstown, LLC
Clearview Electric Inc.
Clearview Solar I, LLC
Cleveland-Cliffs Steel Corporation
Cleveland-Cliffs Steel LLC
Cleveland Electric Illuminating Company
Click Energy, LLC
CL-Viaduct Holding LLC
CMS Energy Resource Management Company
Comity Inc.
Coaltrain Energy LP
Coastal Strategies, LLC
COI Energy Services, Inc.
Collegiate Clean Energy, LLC
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Constellation Energy Generation, LLC
Constellation NewEnergy, Inc.
Consumer Protection and Advocate Division of the Tennessee Attorney General
Consumers Energy Company
Convergent Energy and Power LP
Cordova Energy Company LLC
Cork Oak Solar LLC
Cornerstone Gas, L.L.C.
Corona Power LLC
Cottontail Solar 1, LLC
Cottontail Solar 2, LLC

Cottontail Solar 3, LLC
Cottontail Solar 4, LLC
Cottontail Solar 5, LLC
Cottontail Solar 6, LLC
Cottontail Solar 7, LLC
Cottontail Solar 8, LLC
County of Frederick, VA
Covanta Energy Marketing LLC
Covanta Union, LLC
CP Energy Marketing (US) Inc.
CPV Backbone Solar, LLC
CPV Fairview, LLC
CPV Keasbey, LLC
CPV Maple Hill Solar, LLC
CPV MARYLAND, LLC
CPV Power Holdings, LP
CPV Retail Energy LP
CPV Shore, LLC
CPV Three Rivers, LLC
CPV Rogue's Wind, LLC
Crescent Ridge LLC
Crete Energy Venture, LLC
Crossroads Solar I, LLC
Cube Hydro Partners, LLC
Current Energy and Renewables Inc.
Customized Energy Solutions, Ltd.
CWP Energy Inc.
Cypress Creek Renewables, LLC
Danske Commodities US LLC
Darby Energy, LLLP
Darby Power, LLC
Dart Container Corporation of Pennsylvania
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DCO Energy, LLC
Decatur Energy Center, LLC
Delaware Division of the Public Advocate
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy, LLC
Diamond Energy East, LLC
Diamond Retail Energy, LLC
Diamond State Generation Partners, LLC

Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
Divine Power, Inc.
Dominion Energy Generation Marketing, Inc.
Dominion Energy South Carolina, Inc.
Domtar Paper Company, LLC
Doral Renewables LLC
Doswell Limited Partnership
DPL Energy Resources, LLC
Drake Power, LLC
DTE Atlantic, LLC
DTE Energy Trading, Inc.
DTN, LLC
Duke-American Transmission Company, LLC
Duke Energy Business Services, LLC
Duke Energy Carolinas, LLC
Duke Energy Florida, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Progress, LLC
Duke Energy Renewable Services, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Duquesne Power LLC
DV Trading, LLC
DXT Commodities North America Inc.
Dynamix Energy Services Company, LLC
Dynasty Energy California Inc.
Dynasty Power Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, LLC
Eagle Creek Hydro Holdings, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings L.L.C.
Eastern Generation, LLC
Eastern Shore Solar LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCap Network, LLC
EcoGrove Wind, LLC
EcoPlus Power, LLC
EDF Trading North America, LLC

Edgecombe Solar LLC
EDP Renewables North America, LLC
EF Kenilworth LLC
EFS Parlin Holdings, LLC
Electranet REP I, LLC
Elgin Energy Center, LLC
Eligo Energy, LLC
Elk Hill Solar 1, LLC
Elk Hill Solar 2, LLC
Elk Run Storage LLC
Elliot Bay Energy Trading, LLC
Elmagin Power Fund LLC
Elm Line LLC
Elmwood Park Power, LLC
Elwood Energy LLC
Emera Energy Services, Inc.
Emporia Hydropower Limited Partnership
Endurance Energy Midwest LLC
Enel Green Power Hilltopper Wind, LLC
Enel Trading North America, LLC
Enel X North America, Inc.
Energo Power & Gas LLC dba Energo
Energy Authority, Inc. (The)
Energy Center Dover LLC
Energy Cooperative Association of Pennsylvania
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Power Investment Company, LLC
Energy Service Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Enerwise Global Technologies, LLC
Engelhart CTP (US) LLC
ENGIE Energy Marketing NA, Inc.
ENGIE Power & Gas LLC
ENGIE Resources LLC
EnPowered USA Inc.
Entergrid Fund I LLC
EPP Renewable Energy, LLC
ESC Harrison County Power, LLC
Essential Power OPP, LLC
Essential Power Rock Springs, LLC
ETC Endure Energy L.L.C.

Evergreen Gas & Electric, LLC
Evergy Kansas Central, Inc.
Evergy Metro, Inc.
Everyday Energy, LLC
Exelon Business Services Company, LLC
Fairless Energy, L.L.C.
Fantods LLC
Fermata Energy, LLC
Fern Solar LLC
FirstEnergy Pennsylvania Electric Company
First Point Power, LLC
FiTran Fund LP
Five Elements Energy LLC
Five Forks Solar, LLC
Florida Power & Light Company
Forest Investment Group, LLC
Forked River Power LLC
Fowler Ridge Wind Farm LLC
Fowler Ridge II Wind Farm LLC
Fowler Ridge III Wind Farm LLC
Fowler Ridge IV Wind Farm LLC
Foxhound Solar, LLC
FP East Capital Partners LLC
Franklin Power LLC
Frasier Solar, LLC
Freepoint Commodities LLC
Freepoint Energy Solutions LLC
Fresh Air Energy XVIII, LLC
Fresh Air Energy XXXV, LLC
G&G Energy, Inc.
G&S Wantage Solar, LLC
Galilean Electricae LLC
Gallus Capital LLC
Galt Power, Inc.
Gavin Power, LLC
GBE Energy Marketing Inc.
GDF SUEZ Energy Resources NA, Inc.
Geenex Solar LLC
Genbright LLC
Gen IV Investment Opportunities, LLC
GenOn Energy Management, LLC
GenOn Mid-Atlantic, LLC
GenOn Power Midwest, LP
GenOn REMA, LLC
Gen Ops, LLC
Geodesic 2 LLC

Georgia Power Company
Gerdau Ameristeel Energy, Inc
GlidePath Power Operations LLC
Goldin LLC
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy Storage, LLC
Grange Solar, LLC
Granger Energy of Honey Brook, LLC
Grantham Energy Corporation
Grasshopper Energy LLC
Grays Ferry Cogeneration Partnership
Great American Gas & Electric, LLC
Great American Power, LLC
Great Barrington Energy Fund LP
Great Cove Solar I LLC
Great Cove Solar II LLC
Great Falls Hydroelectric Company Limited Partnership
Green Energy NE LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Green River Holdings, LLC
Greensville County Solar Project, LLC
GRG ENERGY LLC
GridBeyond US, LLC
Gridforce Energy Management, LLC
Gridmatic Inc.
Gridmatic Panicum LLC
Grid Power Direct, LLC
Group628, LLC
GSG, LLC
GSG 6, LLC
Guernsey Power Station LLC
Guidehouse Inc.
Gunvor USA LLC
Guzman Energy LLC
H.A. Wagner LLC
H.Q. Energy Services (U.S.), Inc.
Hagerstown Light Department
Half Moon Ventures, LLC
Hamilton Liberty LLC
Hamilton Patriot LLC
Hammond Solar, LLC
Handsome Lake Energy, LLC

Harborside Energy, LLC
Hardin Solar Energy LLC
Hardin Wind LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartree Partners, LP
Harts Mill Solar, LLC
Harvey Solar I, LLC
Hawks Nest Hydro LLC
Hazle Spindle, LLC
Hazleton Generation LLC
HD Project One, LLC
Headwaters Wind Farm LLC
Headwaters Wind Farm II LLC
Hecate Energy Highland LLC
Helix Ironwood, LLC
Hemlock Solar, LLC
Hemsworth Capital LP
Hemsworth Capital Midwest LP
Heritage Power Marketing, LLC
Hexis Energy Trading, LLC
Hickory Run Energy, LLC
Highland North LLC
High Point Solar LLC
High Trail Wind Farm LLC
Hillcrest Solar I, LLC
Hill Top Energy Center, LLC
Holcim (US), Inc.
Holocene Finance, LLC
Homer City Generation, LP
Hoosier Energy REC, Inc.
Horizon Power and Light, LLC
H-P Energy Resources, LLC
Hudson Energy Services LLC
Hudson Transmission Partners, LLC
Hummel Station, LLC
HXNAir Solar One, LLC
Icetec.com, Inc.
Icetec Energy Services, Inc.
IDT Energy, Inc.
IHG Core Holdings, Ltd.
IHS Global Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Illinois Power Marketing Company
IMG Midstream LLC
In Commodities US LLC

Indeck Niles, LLC
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Inerci Capital Inc.
Inertia Power I, LLC
Ingenco Wholesale Power, LLC
Innergex Renewable USA LLC
Innoventive Power LLC
Inspire Energy Holdings, LLC
Intelligent Generation LLC
International Paper Company
Interstate Gas Supply, LLC
Interstate Power and Light Company
Invenergy Energy Management LLC
Invenergy LLC
Invenergy Nelson Expansion LLC
Invenergy Nelson LLC
IPKeys Power Partners, Inc.
IR Energy Management LLC
ISO 1, LLC
ITC Mid-Atlantic Development LLC
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jackson Generation, LLC
Jane Street Energy Trading, LLC
Janus Power LLC
J. Aron & Company LLC
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
Josco Energy IL LLC
Josco Energy USA, LLC
JP Morgan Ventures Energy Corporation
Jupiter Power LLC
Just Energy Limited
Just Energy Solutions Inc.
KDC Solar Green Power LLC
Kendall Power Company LLC
Keni Energy LLC
Kentucky Municipal Energy Agency
Kentucky Power Company
Kestrel Acquisition, LLC
KeyCon Power Holdings LLC
Keystone Appalachian Transmission Company

Keystone-Conemaugh Projects, LLC
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kincaid Generation, LLC
Kingsport Power Company
Kiwi Energy NY LLC
KMC Thermo, LLC
KOREnergy, Ltd.
Kuehne Chemical Company, Inc.
kWantix Trading Fund I,LP
L&P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Lackawanna Energy Center LLC
Lafayette Power LLC
Lancaster County Solid Waste Management Authority
Landaj Investment, LLC
Land O'Lakes, Inc.
Lantar Energy LLC
Lawrenceberg Power, LLC
Lanyard Power Holdings, LLC
LCP Energy LP
Leapfrog Power, Inc.
Lee County Generating Station, LLC
Leeward Asset Management, LLC
Legacy Energy Group, LLC (The)
Lehigh Portland Cement Company
Letterkenny Industrial Development Authority – PA
Lexington Chenoa Wind Farm LLC
Liberty Electric Power, LLC
Liberty Madison Storage LLC
Lightstone Marketing LLC
Lily Pond Solar, LLC
Lincoln Generating Facility, LLC
Linden VFT LLC
LM Power, LLC
LMBE Project Company LLC
Lone Tree Wind, LLC
Long Island Lighting Company d/b/a LIPA
Long Ridge Energy Generation LLC
Longview Power, LLC
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
LQA, LLC
LSP University Park, LLC
LTSTE Investments, LLC

Lyons Solar, LLC
Macquarie Energy LLC
Macquarie Energy Trading LLC
MAG Energy Solution, Inc.
Mahoning Creek Hydroelectric Company, LLC
Major Energy Electric Services, LLC
Manatee Transmission LLC
Maple Analytics, LLC
Marginal Unit, Inc.
Marina Energy, LLC
Martins Creek, LLC
Marubeni Power International, Inc.
Maryland Office of People's Counsel
Maryland Solar LLC
Mattawoman Energy, LLC
MC Project Company LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
Meadow Lake Wind Farm V, LLC
Meadow Lake Wind Farm VI LLC
MeadWestvaco Corporation
Median Energy Corp.
Median Energy IL LLC
Median Energy PA LLC
Mega Energy of Illinois, LLC
Mehoopany Wind Energy LLC
Mendota Hills, LLC
Mercuria Energy America, LLC
Mercuria SJAK Trading, LLC
Merrill Lynch Commodities, Inc.
Messer LLCsouth
Messer Energy Services, Inc.
MeterGenius, Inc.
MFT Energy US 1 LLC
Miami Valley Lighting, LLC
Mianus River Energy, LLC
Michigan Department of Attorney General, Environment, Natural Resources & Agriculture Division
Michigan Public Power Agency
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Mid-Atlantic Interstate Transmission, LLC
MidAtlantic Power Partners, LLC

Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Milan Energy LLC
Milford Solar LLC
Mississippi Power Company
Mitsui Bussan Commodities Ltd.
Mitsui & Co. Energy Marketing and Services (USA), Inc.
Monongahela Power Company d/b/a Allegheny Power
Monterey MA LLC
Montour, LLC
Montpelier Generating Station, LLC
Monument Generating Station, LLC
Morgan Stanley Capital Group Inc.
Morgan Stanley Services Group Inc.
Morris Cogeneration, L.L.C
Mosaic Power, LLC
Moundsville Power, LLC
Moxie Freedom LLC
MP2 Energy LLC
MP2 Energy NE LLC dba Shell Energy Solutions
MPCF I, LLC
MPower Energy NJ LLC
Mt. Carmel Cogen, Inc.
National Gas & Electric, LLC
Nautilus Power, LLC
Nautilus Solar Energy, LLC
NDC Partners, LLC
NedPower Mount Storm, LLC
NEPM II, LLC
Neptune Regional Transmission System, LLC
Newark Energy Center, LLC
New Covert Generating Company, LLC
New Creek Wind LLC
New Jersey Division of the Ratepayer Advocate
New Jersey Transit Corporation
New Wave Energy, LLC
New York Power Authority
New York State Electric & Gas Corporation
Newark Bay Cogeneration Partnership, L.P.
New Road Power, LLC
NextEra Energy Bluff Point, LLC
NextEra Energy Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NextEra Energy Transmission, LLC

NextEra Energy Transmission MidAtlantic Indiana, Inc.
NextPower III US Holdco Inc.
Nexus Energy Inc.
NG Renewables Energy Marketing, LLC
NJR Clean Energy Ventures Corporation
NJR Clean Energy Ventures II Corporation
NJR Clean Energy Ventures III Corporation
Nodal Exchange, LLC
Nordic Energy Services LLC
North 301 Solar, LLC
North American Power and Gas, LLC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
North Hanover Solar W2-082, LLC
Northampton Generating Company, L.P.
Northeastern REMC
Northeast Maryland Waste Disposal Authority
Northern Illinois Municipal Power Agency
Northern Indiana Public Service Company
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northstar Trading Ltd.
Northwest Ohio Wind, LLC
NRG Curtailment Solutions, Inc.
NRG Power Marketing, LLC
NRGStream LLC
NTE Ohio, LLC
nTherm, LLC
NuEnergen, LLC
Oak Trail Solar, LLC
OCI Solar Power, LLC
Octopus Energy LLC
Office of the Attorney General, Kentucky
Office of the People’s Counsel for the District of Columbia
O.H. Hutchings CT, LLC
Ohio Consumer’s Counsel
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Old Mission Energy Trading LLC
Olympus Power, LLC
One Energy Enterprises LLC
Ontario Power Generation Energy Trading, Inc.
Ontario Power Generation Inc.

Ontelaunee Power Operating Company, LLC
Open Road Renewables, LLC
Oregon Clean Energy, LLC
Orennia US LLC
Orsted Onshore North America, LLC
Osaka Gas USA Corporation
Owensboro Municipal Utilities
Oxbow Creek Energy LLC
Pacific Summit Energy LLC
Palladium Energy, LLC
Palm Energy LLC
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Panther Creek Power Operating, LLC
Park Power LLC
Parkway Generation Operating LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
Paulding Wind Farm III LLC
Paulding Wind Farm IV LLC
Pay Less Energy, LLC
PBF Power Marketing, LLC
Peak Energy Capital LP
Peakstone Energy, LLC
PECO Energy Company
Pedricktown Cogeneration Company LP
Pegasus Energy Futures LLC
PEI Power LLC
PEI Power II, LLC
Peninsula Power, LLC
Penncat Corporation
Pennoni Associates Inc.
Pennsylvania Grain Processing LLC
Pennsylvania Office of Consumer Advocate
Pennsylvania Renewable Resources, Associates
Perast Fund LP
Pharentram Energy Services, Ltd.
Philadelphia Energy Solutions Refining and Marketing LLC
Phillips 66 Energy Trading LLC

Piedmont Energy Fund, L.P.
Pine Gate Mid-Atlantic, LLC
Pinesburg Solar LLC
Pinnacle Power LLC
Pixelle Specialty Solutions LLC
Plains Solar, LLC
Plant-E Corp.
Polaris Power Services LLC
Potomac Edison Company (The) d/b/a Allegheny Power
Potomac Electric Power Company
Potomac Energy Center, LLC
Power Analytics Software, Inc.
Power Engineers, Incorporated
Power Supply Services, LLC
Power Up Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation dba PPL Utilities
Prairieland Energy, Inc.
Praxair, Inc.
Precept Power LLC
Procter & Gamble Paper Products Company (The)
Prospect Power, LLC
Providence Heights Wind, LLC
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
PSEG Nuclear LLC
Public Service Electric and Gas Company
Public Staff – North Carolina Utilities Commission
Pure Energy, Inc.
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Quattro Energy LP
Radford's Run Wind Farm, LLC
Rainbow Energy Marketing Corporation
Rainbow Energy Ventures LLC
Rausch Creek Electric Power Holdings, LLC
Realgy, LLC
Recurrent Energy, LLC
Red Oak Power, LLC
Red Wolf TX2, LLC
Refinitiv US LLC
Reliant Energy Northeast, LLC
Renaissance Power & Gas, Inc.
Renergy Inc.
Renewable Energy Aggregators Inc.

Rensselaer Generating LLC
RES America Developments Inc.
ResCom Energy, LLC
Residents Energy, LLC
Respond Power, LLC
Rhei Energy Partners LP
Richfield Solar Energy LLC
Richland-Stryker Generation LLC
RI-Corp. Development, Inc.
River Bay Commodities, LLC
RiverCrest Power-South, LLC
Riverside Generating Company, L.L.C.
Riverstart Solar Park LLC
Rochester Gas and Electric Corporation
Rockfish Solar LLC
Rockland Electric Company
Rocky Road Power, LLC
Rodan Energy Solutions (USA) Inc.
Rolling Hills Generating, L.L.C.
Rose Gold Solar, LLC
Roseton Generating LLC
Roth Rock Wind Farm, LLC
Roundtop Energy LLC
Royal Bank of Canada
RPA Energy, Inc.
RTP Controls, Inc
RTR Energy Solutions LLC
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
RWE Renewables Americas, LLC
Safe Harbor Water Power Corporation
Sanitas Power, LLC
Santanna Energy Services
Saracen Energy East LP
Saracen Energy Midwest LP
Saracen Energy West LP
Saracen Power LP
Saugatuck River Power Trading LLC
S.C. Energy Partners LLC
Schuylkill Energy Resources, Inc.
Scout Storage LLC
Scrubgrass Generating Company, L.P.
Scylla Energy LLC
Seneca Generation, LLC
Seneca Trading LLC

SESCO ENTERPRISES LLC
Seven Islands Environmental Solutions, LLC
Severn River Power LLC
Seward Generation, LLC
SFE Energy, Inc.
Shell Energy North America (U.S.), L.P.
Shepard’s Neck Point LLC
Shipley Choice LLC
Sidney, LLC
Siemens Industry, Inc.
Silver Run Electric, LLC
S.J. Energy Partners, Inc.
SmartEnergy Holdings, LLC
SmartestEnergy US LLC
Smart Wires Inc.
SociVolta Inc.
Solios Power Mid-Atlantic Trading LLC
Sol Madison Solar, LLC
Southampton Solar LLC
South Bay Energy Corp.
Southeastern Chester County Refuse Authority
Southeastern Power Administration
Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Maryland Electric Cooperative, Inc.
Southern Power Company
South Field Energy LLC
South Jersey Energy Company
Spark Energy, LLC
Spartacus Energy Services LLC
Spotlight Power LLC
sPower Energy Marketing, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Spruance Operating Services, LLC
Spruce Power Trading, LLC
Standard Gas & Electric, LLC
Star Jasmine Houston LLC
STATARB INVESTMENTS LLC
Sterling Partners Energy Investors LLC
St. Joseph Energy Center, LLC
Stones DR, LLC
Stoney Creek Wind Farm, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC

Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Strom Power, LLC
Summer Energy Midwest, LLC
Summit Farms Solar, LLC
SunCoke Energy, Inc
Sunflower Solar LLC
SunSea Energy LLC
Sunshaw Power Trading, LLC
Sun Tribe Development LLC
Susquehanna Nuclear, LLC
Sustaining Power Solutions LLC
Syncarpha Solar, LLC
SYSO Inc.
Tait Electric Generating Station, LLC
Talen Energy Marketing, LLC
Tangent Energy Solutions, Inc.
Tatanka Wind Power, LLC
TC Energy Marketing Inc.
TEC Energy Inc.
TEC Trading, Inc.
Tenaska Pennsylvania Partners, LLC
Tenaska Power Management, LLC
Tenaska Power Services Co.
Tenaska Virginia Partners, L.P.
Tennessee Valley Authority (The)
TerraForm IWG Acquisition Holdings II, LLC
Texas Retail Energy, LLC
Teza Technologies LLC
The Hartz Group
The Highlands Energy Group, LLC
Think Energy, LLC
Thordin ApS
Thurmont Municipal Light Company
Tidal Energy Marketing (U.S.) L.L.C.
Tilton Energy LLC
Timber Road Solar Park LLC
TimberRock Consulting LLC
Tios Capital, LLC
Titan Gas and Power
Todd Solar LLC
Toledo Edison Company (The)
Tomorrow Energy Corp
Town of Berlin, Maryland
Town of Williamsport
Town Square Energy East, LLC

Tradewind Energy, Inc.
Trafigura Trading LLC
TrailStone Energy Marketing, LLC
Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
Transource Energy, LLC
Transource Maryland, LLC
Transource Pennsylvania, LLC
Transource West Virginia, LLC
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Tri Global Energy, LLC
TrueLight Commodities, LLC
Trustees of the University of Pennsylvania
Tupelo Solar I, LLC
TWE Myrtle Solar Project, LLC
Twin Eagle Resource Management, LLC
Tyne Hill Investments LP
Tyr Energy, LLC
UGI Development Company
UGI Energy Services, LLC
UGI Utilities, Inc.
Uncia Energy LP – Series B
Union Electric Company d/b/a Ameren Missouri
Union Ridge Solar, LLC
University Park Energy, LLC
UN-School House Holding LLC
Urban Grid Solar Projects, LLC
V3 Commodities Group, LLC
VCIOM, LLC
VECO Power Trading, LLC
Velocity American Energy Master I, LP
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia Solar 2017 Projects LLC
Virginia State Corporation Commission
Viribus Fund LP
Viridian Energy Ohio LLC
Viridian Energy PA, LLC
Viridity Energy Solutions Inc.

Vista Energy Marketing, L.P.
Vitol, Inc.
Voltus, Inc.
Wabash Valley Power Association, Inc.
Volunteer Energy Services, Inc.
Walden Renewables Development LLC
Walnut Ridge Wind, LLC
Walleye Power, LLC
Waterford Power, LLC
Waverly Solar, LLC
Wellsboro Electric Company
West Deptford Energy, LLC
Western Reserve Energy Services, LLC
West Virginia Consumer Advocate Division
WGL Energy Services, Inc.
Wheelabrator Baltimore, L.P.
Wheelabrator Falls Inc.
Wheelabrator Frackville Energy Company, Inc.
Wheelabrator Gloucester Company, L.P.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
White Peak Energy LLC
Whitetail Solar 1, LLC
Whitetail Solar 2, LLC
Whitetail Solar 3, LLC
Whitmore Solar, LL
Whitney Hill Wind Power, LLC
Wildcat Wind Farm I, LLC
Wilkinson Solar LLC
Willey Battery Utility, LLC
Wisconsin Power and Light Company
WM Renewable Energy, LLC
Wolf Hills Energy, LLC
Wolf Run Energy LLC
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
WP&G Holdings, LLC
WPPI Energy
Wrigley Capital LLC
Wyandot Solar LLC
XO Energy MA, LP
XO Energy MA2, LP
XO Energy MA3, LP
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC

XOOM Energy Ohio, LLC
XOOM Enegy Washington D.C., LLC
Xoom Energy, LLC
Yankee Street, LLC
Yellow Jacket Energy, LLC
Yes Energy LLC
York County Solid Waste and Refuse Authority
York Generation Company LLC
York Haven Power Company, LLC
Zongyi Solar America Co. Ltd.

Schedule 13

Rates, Terms, and Conditions of Service for PJM Settlement, Inc.

In accordance with the order of the Commission, dated September 3, 2010, in Docket No. ER10-1196-000, this Schedule 13 establishes as a shared tariff the rates, terms, and conditions of PJMSettlement services as set forth below.

a) Under the Tariff and Operating Agreement, PJM administers the provision of transmission service and associated ancillary services to customers and operates and administers various centralized electric power and energy markets.

b) Under the Tariff and Operating Agreement, PJMSettlement is the entity that (i) contracts with customers and conducts financial settlements regarding the use of the transmission capacity of the Transmission System that PJM, as the Transmission Provider, administers under the PJM Tariff and this Agreement; (ii) is the Counterparty with respect to the agreements and "pool" transactions in the centralized markets that PJM, as the Transmission Provider, administers under the PJM Tariff and this Agreement; and (iii) is the Counterparty to Financial Transmission Rights and Auction Revenue Rights instruments held by a Market Participant.

c) In accordance with Operating Agreement section 3.3, unless otherwise expressly stated in the Tariff or Operating Agreement, PJMSettlement is the Counterparty to the customers purchasing Transmission Service and Network Integration Transmission Service, and to the other transactions with customers and other entities under the PJM Tariff or this Agreement. Accordingly, all rates, terms, and conditions of Transmission Service, Network Integration Transmission Service, and other transactions with entities under this Agreement, set forth throughout this Agreement, shall constitute rates, terms, and conditions of PJMSettlement service.

d) Each seller shall be deemed to warrant that it holds good title to the products that are the subject of transactions it undertakes with PJMSettlement as a buyer. In accordance with and consistent with this warranty, PJMSettlement in turn warrants that it holds good title to the products that are the subject of transactions it undertakes with each buyer. The warranties set forth in this paragraph are provided only in connection with the requirements established by the FERC for PJMSettlement to serve as a Counterparty. Accordingly, any enforcement of, or challenge to, the warranties set forth in this paragraph shall be heard exclusively before the FERC. This paragraph is not intended to create independent rights or obligations for any party under the Uniform Commercial Code or common law that might be enforceable in federal or state courts or in any forum other than FERC.

e) In accordance with Operating Agreement, section 3.3, PJMSettlement shall not be the contracting party to other non-transmission transactions that are (1) bilateral transactions between market participants reported to the Transmission Provider, and (2) self-supplied or self-scheduled transactions reported to the Transmission Provider.

f) In accordance with Operating Agreement, section 3.3, PJMSettlement shall not be the Counterparty with respect to agreements and transactions regarding the Transmission Provider's administration of Tariff, Part IV Tariff, Part VI, Tariff, Schedule 1, Tariff, Schedule 9 through Tariff, Schedule 9-MMU, Tariff, Schedule 10-NERC, Tariff, Schedule 10-RFC, Tariff, Schedule 14, Tariff, Schedule 16, Tariff, Schedule16-A, and Tariff, Schedule 17.

g) The costs of services provided by PJMSettlement for the benefit of Market Participants and Transmission Customers shall be collected by PJMSettlement through the charge set forth in Tariff, Schedule 9-PJMSettlement.

h) Billing and payment provisions applicable to PJMSettlement are set forth in Tariff, section 7 and Operating Agreement, section 14, 14A, and 14B.

RESOLUTION TO AMEND THE PROCEDURES REQUIRING THE RETENTION OF AN INDEPENDENT CONSULTANT TO PROPOSE A LIST OF CANDIDATES FOR THE BOARD OF MANAGERS ELECTION FOR 2001

1. For the election of Board Members at the Annual Meeting in 2001, an independent consultant to prepare a list of persons qualified and willing to serve on the PJM Board in accordance with Section 7.1 of the Operating Agreement shall not be required.
2. Section 7.1 of the Operating Agreement shall be deemed to be amended by the foregoing for the election at the Annual Meeting in 2001.
3. PJM shall make the necessary regulatory filings with the Federal Energy Regulatory Commission to implement the foregoing.

DATA REQUEST

KPSC PHDR_2	Refer to the Integrated Resource Plan (IRP) Table 5, page 88 of 1182 and Table 6, page 90 of 1182. a. Identify the inputs, or types of costs, included in the variable operational and maintenance (VOM) costs and fixed operational and maintenance (FOM) costs for the NGCT and NGCC units referenced in Table 5 and Table 6. b. Provide a copy of any description of the inputs to the VOMs and FOMs from the relevant source i.e. the description from EIA's 2022 AEO or 2022 National Renewable Energy Laboratory's annual technology baseline. c. Provide the approximate MWh effect of the $79/MW start-up costs referenced in footnote 17 based on the expected operation of the NGCTs in the preferred plan in the reference scenario, and explain how the MWh effect was calculated.

RESPONSE

a & b. VO&M costs for new gas simple cycle turbines (CT) and Combined Cycle turbines (CC) were informed by EIA's power plant costs originally developed as part of the AEO2020 report. These costs have been the basis for continued updates in subsequent AEO technology costs. The report is included as KPCO_R_KPSC_PHDR_2_Attachment1.

Section 6.3 of the report attached discusses the O&M costs assumed in the Simple Cycle CTs. Variable O&M (VOM) costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of Equivalent Operating Hours ("EOH").

For Combined Cycles, Section 8.3 of the report attached discusses the Variable O&M costs for the Combined Cycle resources. VOM costs include consumable commodities such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the Steam Generator over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOH the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH.

c. Please refer to KPSC 1_14.

Witness: Gregory J. Soller

Independent Statistics & Analysis
U.S. Energy Information Administration

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

February 2020

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

To accurately reflect the changing cost of new electric power generators for AEO2020, EIA commissioned Sargent & Lundy (S&L) to evaluate the overnight capital cost and performance characteristics for 25 electric generator types. The following report represents S&L's findings. A separate EIA report, "Addendum: Updated Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Plants in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)," details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number 89303019-CEI00022. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained therein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

Sargent & Lundy

Capital Cost Study

Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies

Prepared for
U.S. Energy Information Administration,
an agency of the U.S. Department of Energy

eia Independent Statistics & Analysis
U.S. Energy Information Administration

FINAL REPORT | DECEMBER 2019
Contract No. 89303019CEI00022
SL-014940 | Project No. 13651.005

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Sargent & Lundy is one of the oldest and most experienced full-service architect engineering firms in the world. Founded in 1891, the firm is a global leader in power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Sargent & Lundy delivers comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance—with an emphasis on quality and safety. The firm serves public and private sector clients in the power and energy, gas distribution, industrial, and government sectors.

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000

VERSION LOG

Version	Issue Date
Draft	June 14, 2019
Interim Final Report	August 6, 2019
Final	August 30, 2019
Final – Rev 1.	December 9, 2019

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APPENDIXES

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
°F	degrees Fahrenheit
AC	alternating current
ACC	air-cooled condenser
BESS	battery energy storage system
BFB	bubbling fluidized bed
BOP	balance of plant
Btu/kWh	British thermal unit(s) per kilowatt hour
CC	combined cycle
CCS	carbon capture and sequestration
CO	carbon monoxide
CO_2	carbon dioxide
CSP	Concentrating Solar Power
CT	combustion turbine
DC	direct current
DCS	distributed control system
EIA	U.S. Energy Information Administration
EOH	equivalent operating hours
EPC	engineering, procurement, and construction
FGD	flue gas desulfurization
G&A	general and administrative costs
GSU	generator step-up transformer
HHV	higher heating value
HRSG	heat recovery steam generator

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
Hz	hertz
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt hour(s)
lb/MMBtu	pound(s) per one million British thermal units
LNB	low-NO_X burner
MVA	megavolt ampere
MW	megawatt(s)
MWh	megawatt hour(s)
NO_X	nitrogen oxide
O&M	operations and maintenance
OEM	original equipment manufacturer
OFA	overfire air
psia	pounds per square inch absolute
PV	photovoltaic
RICE	reciprocating internal combustion engine
SCADA	Supervisory Control and Data Acquisition
SCR	selective catalytic reduction
SMR	small modular reactor
SO_2	sulfur dioxide
STG	steam turbine generator
USC	ultra-supercritical
V	volt

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
WFGD	wet flue gas desulfurization
WTG	wind turbine generator
ZLD	zero liquid discharge

Introduction

INTRODUCTION

The U.S. Energy Information Administration (EIA) retained Sargent & Lundy to conduct a study of the cost and performance of new utility-scale electric power generating technologies. This report contains our cost and performance estimates for 25 different reference technology cases. The EIA will use these estimates to improve the EIA's Electricity Market Module's ability to represent the changing landscape of electricity generation and thus better represent capital and non-fuel operating costs of generating technologies being installed or under consideration for capacity expansion. The Electricity Market Module is a submodule within the EIA's National Energy Modeling System, a computer-based energy supply modeling system used for the EIA's *Annual Energy Outlook* and other analyses.

Sargent & Lundy developed the characteristics of the power generating technologies in this study based on information about similar facilities recently built or under development in the United States and abroad. Developing the characteristics of each generating technology included the specification of representative plant sizes, configurations, major equipment, and emission controls. Sargent & Lundy's cost assessment included the estimation of overnight capital costs, construction lead times, and contingencies as well as fixed and variable operating costs. We also estimated the net plant capacity, net plant heat rates, and controlled emission rates for each technology studied. We performed our assessments with consistent estimating methodologies across all generating technologies.

COST & PERFORMANCE OF TECHNOLOGIES

The following table lists all the power generating technologies we assessed in this study.

Table 1 — List of Reference Technologies

Case No.	Technology	Description
1	650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield	1 x 735 MW Gross
2	650 MW Net, Ultra-Supercritical Coal 30% Carbon Capture	1 x 769 MW Gross
3	650 MW Net, Ultra-Supercritical Coal 90% Carbon Capture	1 x 831 MW Gross
4	Internal Combustion Engines	4 x 5.6 MW
5	Combustion Turbines – Simple Cycle	2 x LM6000
6	Combustion Turbines – Simple Cycle	1 x GE 7FA
7	Combined-Cycle 2x2x1	GE 7HA.02
8	Combined-Cycle 1x1x1, Single Shaft	H Class
9	Combined-Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture	H-Class
10	Fuel Cell	34 x 300 kW Gross

Case No.	Technology	Description
11	Advanced Nuclear (Brownfield)	2 x AP1000
12	Small Modular Reactor Nuclear Power Plant	12 x 50-MW Small Modular Reactor
13	50-MW Biomass Plant	Bubbling Fluidized Bed
14	10% Biomass Co-Fire Retrofit	300-MW PC Boiler
15	Geothermal	Binary Cycle
16	Internal Combustion Engines – Landfill Gas	4 x 9.1 MW
17	Hydroelectric Power Plant	New Stream Reach Development
18	Battery Energy Storage System	50 MW | 200 MWh
19	Battery Energy Storage System	50 MW | 100 MWh
20	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.8 MW WTG
21	Onshore Wind – Small Plant Footprint: Coastal Region	50 MW | 2.8 MW WTG
22	Fixed-bottom Offshore Wind: Monopile Foundations	400 MW | 10 MW WTG
23	Concentrating Solar Power Tower	with Molten Salt Thermal Storage
24	Solar PV w/ Single Axis Tracking	150 MW_{AC}
25	Solar PV w/ Single Axis Tracking + Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage

Acronym Definitions:

- BESS = battery energy storage system
- Btu/kWh = British thermal units per kilowatt hour
- CC = combined cycle
- CCS = carbon capture and sequestration
- CT = combustion turbine
- kW = kilowatt
- MW = megawatt
- MW_{AC} = megawatt alternating current
- MWh = megawatt hour
- PV = photovoltaic
- USC = ultra-supercritical
- WTG = wind turbine generator

As part of the technology assessment, Sargent & Lundy reviewed recent market trends for the reference technologies using publicly available sources and in-house data. We also used our extensive background in power plant design and experience in performing similar cost and performance assessments. Using a combination of public and internal information sources, Sargent & Lundy identified the representative costs and performance for the reference technologies.

COST & PERFORMANCE ESTIMATES SUMMARY

Table 2 summarizes all technologies examined, including overnight capital cost information, fixed operating and maintenance (O&M) costs, and variable non-fuel O&M costs as well as emissions estimates for new installations (in pounds per one million British thermal units [lb/MMBtu]).

Table 2 — Cost & Performance Summary Table

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/Kwh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	NOx (lb/MMBtu)	SO2 (lb/MMBtu)	CO2 (lb/MMBtu)
1	650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield	1 x 735 MW Gross	650	8638	3676	40.58	4.50	0.06	0.09	206
2	650 MW Net, Ultra-Supercritical Coal 30% Carbon Capture	1 x 769 MW Gross	650	9751	4558	54.30	7.08	0.06	0.09	144
3	650 MW Net, Ultra-Supercritical Coal 90% Carbon Capture	1 x 831 MW Gross	650	12507	5876	59.54	10.98	0.06	0.09	20.6
4	Internal Combustion Engines	4 x 5.6 MW	21	8295	1810	35.16	5.69	0.02	0	117
5	Combustion Turbines – Simple Cycle	2 x LM6000	105	9124	1175	16.30	4.7	0.09	0.00	117
6	Combustion Turbines – Simple Cycle	1 x GE 7FA	237	9905	713	7.00	4.5	0.03	0.00	117
7	Combined-Cycle 2x2x1	GE 7HA.02	1083	6370	958	12.20	1.87	0.0075	0.00	117
8	Combined-Cycle 1x1x1, Single Shaft	H Class	418	6431	1084	14.1	2.55	0.0075	0.00	117
9	Combined-Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture	H-Class	377	7124	2481	27.6	5.84	0.0075	0.00	11.7
10	Fuel Cell	34 x 300 kW Gross	10	6469	6700	30.78	0.59	0.0002	0	117
11	Advanced Nuclear (Brownfield)	2 x AP1000	2156	10608	6041	121.64	2.37	0	0	0
12	Small Modular Reactor Nuclear Power Plant	12 x 50-MW Small Modular Reactor	600	10046	6191	95.00	3.00	0	0	0
13	50-MW Biomass Plant	Bubbling Fluidized Bed	50	13300	4097	125.72	4.83	0.08	<0.03	206
14	10% Biomass Co-Fire Retrofit	300-MW PC Boiler	30	+ 1.5%	705	25.57	1.90	0%–20%	-8%	-8%
15	Geothermal	Binary Cycle	50	N/A	2521	128.544	1.16	0	0	0

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/Kwh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	NOx (lb/MMBtu)	SO2 (lb/MMBtu)	CO2 (lb/MMBtu)
16	Internal Combustion Engines – Landfill Gas	4 x 9.1 MW	35.6	8513	1563	20.1	6.2	0.02	0	117
17	Hydroelectric Power Plant	New Stream Reach Development	100	N/A	5316	29.86	0	0	0	0
18	Battery Energy Storage System	50 MW | 200 MWh	50	N/A	1389 (347 $/kWh)	24.8	0	0	0	0
19	Battery Energy Storage System	50 MW | 100 MWh	50	N/A	845 (423 $/kWh)	12.9	0	0	0	0
20	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.82 MW WTG	200	N/A	1265	26.34	0	0	0	0
21	Onshore Wind – Small Plant Footprint: Coastal Region	50 MW | 2.78 MW WTG	50	N/A	1677	35.14	0	0	0	0
22	Fixed-bottom Offshore Wind: Monopile Foundations	400 MW | 10 MW WTG	400	N/A	4375	110	0	0	0	0
23	Concentrating Solar Power Tower	with Molten Salt Thermal Storage	115	N/A	7221	85.4	0	0	0	0
24	Solar PV w/ Single Axis Tracking	150 MW_{AC}	150	N/A	1313	15.25	0	0	0	0
25	Solar PV w/ Single Axis Tracking + Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage	150	N/A	1755	31.27	0	0	0	0

Acronym Definitions:

- $/kW = dollar(s) per kilowatt
- $/kW-year = dollar(s) per kilowatt year
- $/MWh = dollar(s) per megawatt hour
- BESS = battery energy storage system
- Btu/kWh = British thermal units per kilowatt hour
- CC = combined cycle
- CCS = carbon capture and sequestration
- CO_2 = carbon dioxide
- CT = combustion turbine
- kW = kilowatt
- lb/MMBtu = pound(s) per million British thermal units
- MW = megawatt
- MW_{AC} = megawatt alternating current
- MWh = megawatt hour
- PV = photovoltaic
- USC = ultra-supercritical
- WTG = wind turbine generator

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Basis of Estimates

BASIS OF ESTIMATES

BASE FUEL SELECTION

We used the following fuel specifications as a basis for the cost estimates. The tables shown below represent typical fuel specifications for coal, natural gas, and wood biomass.

Table 3 — Reference Coal Specification

Rank	Bituminous
Proximate Analysis (weight %)	
Fuel Parameter	As Received
Moisture	11.2
Ash	9.7
Carbon	63.75
Oxygen	6.88
Hydrogen	4.5
Sulfur	2.51
Nitrogen	1.25
Chlorine	0.29
HHV, Btu/lb	11,631
Fixed Carbon/Volatile Matter	1.2

HHV = higher heating value | Btu/lb = British thermal unit per pound

Table 4 — Reference Natural Gas Specification

Component		Volume Percentage	
Methane	CH_4	93.9	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1	
Nitrogen	N_2	0.8	
Total		100	
		LHV	**HHV**
Btu/lb		20,552	22,793
Btu/scf		939	1,040

Btu/scf = British thermal unit per standard cubic foot

Table 5 — Reference Wood Biomass Specification

Type	Woodchips
Component	Weight %
Moisture	20– 50
Ash	0.1–0.7
Carbon	32
Sulfur	0.01
Oxygen	28
Hydrogen	3.8
Nitrogen	0.1–0.3
HHV, Btu/lb	5,400–6,200

ENVIRONMENTAL COMPLIANCE BASIS

Our technology assessments selected include the best available (emissions) control technology for sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter, mercury, and CO_2, where applicable. Best available control technology guidelines are covered by the U.S. Clean Air Act Title 1, which promotes air quality, ozone protection, and emission limitations. The level of emission controls is based on the following best available control technology guidelines:

- Total source emissions
- Regional environmental impact
- Energy consumption
- Economic costs

Best available control technology is not the most restrictive pollution control standard since it still includes a cost-benefit analysis for technology use. Specific technologies chosen for estimation are further described in their respective cases.

COMBUSTION TURBINE CAPACITY ADJUSTMENTS

Appendix B includes combustion turbine capacity adjustments.

Adjustments for local ambient conditions were made for power plants using combustion turbines (CTs). Since CTs produce power proportional to mass flow and ambient air temperature, relative humidity, and elevation affect air density, these conditions also affect CT performance:

- Temperature affects air density in an inversely proportional relationship and effects combined-cycle (CC) plants' cooling systems, which impacts overall plant performance.
- Relative humidity affects air density in a proportional relationship. For plants with wet cooling (evaporative coolers, wet cooling towers, etc.), relative humidity and temperature determine the effectiveness of that equipment, with the highest effectiveness when the temperature is high and the relative humidity low.
- Elevation affects air pressure and density in an inversely proportional relationship, and it was calculated in this study by using elevation above sea level. This gives the average impact of air pressure on performance, ignoring the short-term effects of weather.

Temperatures and relative humidity used in this adjustment table are based on annual averages for the locations specified. An adjustment factor for the various technologies were compared across locations on a consistent basis.

CAPITAL COST ESTIMATING

Sargent & Lundy has used a top-down capital cost estimating methodology derived from parametric evaluations of costs from actual or planned projects with similar scope and configurations to the generating technology considered. We have used both publicly available information and internal sources from which to establish the cost parameters. In some cases, we have use used portions of more detailed cost estimates to adjust the parametric factors.

The capital cost estimates represent a complete power plant facility on a generic site at a non-specific U.S. location. As applicable, the basis of the capital costs is defined as all costs to engineer, procure, construct, and commission all equipment within the plant facility fence line. As described in the following section, we have also estimated location adjustments to help establish the cost impacts to project implementation in more specific areas or regions within the United States. Capital costs account for all costs incurred during construction of the power plant before the commercial online date. The capital costs are divided between engineering, procurement, and construction (EPC) contractor and owner's costs. Sargent & Lundy assumes that the power plant developer or owner will hire an EPC contractor for turnkey construction of the project. Unless noted otherwise, the estimates assume that the EPC contractor cost will include procurement of equipment, materials, and all construction labor associated with the project. The capital costs provided are overnight capital costs in 2019 price levels. Overnight capital costs represent the total cost a developer would expect to incur during the construction of a project, excluding financing costs. The capital cost breakdowns for the EPC contractor are as follows:

- The civil and structural material and installation cost includes all material and associated labor for civil and structural tasks. This includes both labor and material for site preparation, foundation, piling, structural steel, and buildings.
- The mechanical equipment supply and installation cost includes all mechanical equipment and associated labor for mechanical tasks. This includes both labor and material for equipment installation such as pumps and tanks, piping, valves, and piping specialties.
- The electrical and instrumentation and controls supply and installation includes all costs for transformers, switchgear, control systems, wiring, instrumentation, and raceway.
- The project indirect costs include engineering, construction management, and start-up and commissioning. The fees include contractor overhead costs, fees, and profit.

The owner’s costs primarily consist of costs incurred to develop the project as well as land and utility interconnection costs. The owner’s development costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Outside-the-fence-line costs are considered as owner’s costs. These include electrical interconnection costs and natural gas interconnection and metering costs; however, these costs too are generic and based on nominal distances to substations and gas pipeline laterals. We have also assumed that no substation upgrades would be required for the electrical interconnection. Transmission costs are based on a one-mile transmission line (unless otherwise stated) with voltage ranging from 230 kilovolts (kV) to 500 kV depending on the unit capacity. Land requirements are based on typical land requirements for each technology with per-acreage costs based on a survey of typical site costs across the United States.

The overall project contingency is also included to account for undefined project scope and pricing uncertainty for both capital cost components and owner’s cost components. The levels of contingency differ in some of the estimates based on the nature of the technology and the complexity of the technology implementation.

Locational Adjustments

We estimated the capital costs adjustment factors account for technology implementation at various U.S. locations. Appendix A provides locational adjustment factors.

Craft labor rates for each location were developed from the publication *RS Means Labor Rates for the Construction Industry*, 2019 edition. Costs were added to cover social security, workmen's compensation, and federal and state unemployment insurance. The resulting burdened craft rates were used to develop typical crew rates applicable to the task performed. For each technology, up to 26 different crews were used to determine the average wage rate for each location. For several technologies, relevant internal Sargent & Lundy estimates were used to further refine the average wage rate by using the weighted average based on the crew composition for the specific technology.

Sargent & Lundy used a "30 City Average" based on *RS Means Labor Rates for the Construction Industry* to establish the base location for all the technologies. We measured the wage rate factor for each location against the base rate (the "30 City Average"). The location factors were then improved by adding the regional labor productivity factor; these factors are based on the publication *Compass International Global Construction Costs Yearbook*, 2018 edition. Even though *Compass International Global Construction Costs Yearbook* provides productivity factors for some of the major metro areas in the United States, the productivity factors on the state level were mostly used to represent the typical construction locations of plants for each of the technologies. The final location factor was measured against average productivity factor, which is based on the same 30 cities that are included in the "30 City Average" wage rate.

Environmental Location Factors

Capital cost adjustment factors have also been estimated to account for environmental conditions at various U.S. locations. These environmental location factors, however, do not account for any state or local jurisdictional amendments or requirements that modify the national design codes and standards (i.e., American Society of Civil Engineers, International Building Code. Soil Site Class D for stiff soils was assumed; geotechnical investigation is required to account for site-specific soil conditions that will need to be considered during detailed design. Risk Category II was assumed for all power generating technologies. Each environmental factor was baselined, and the geometric mean was used to determine the combined environmental location factor that accounts for the wind, seismic, snow, and tsunami effects as applicable. To distribute the environmental location factor to the material costs for the civil, mechanical, electrical, carbon capture, and other works for each of the 25 cases, the factor was proportioned based on the assumed effect environmental loading would have on the works. In other words, the concrete foundations support most of the design loading; therefore, the percentage of the environmental loading factor that was distributed to the civil works was typically the highest. The distribution of the environmental loading factor was based on typical general arrangements (i.e., equipment, buildings) for each of the 25 cases.

The environmental location factor for wind is based on ASCE 7-16, and it is based on velocity pressure for enclosed, rigid buildings with flat roofs, which is the most widely used building configuration at power generating stations. The baseline was the approximate average velocity pressure for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for seismic is based on the Seismic Design Category, which is determined based on site-specific coefficients[1] and the calculated Mapped Spectral Response or Design Spectral Acceleration. The baseline was Seismic Design Category B; therefore, the factor was reduced for Seismic Design Category A and increased for Seismic Design Category C and D. None of the locations selected were Seismic Design Category E or F due in part to the assumed soil Site Class D.

The environmental location factor for snow loading is based on an Importance Factor of 1.00. The ground snow load was determined using the ASCE 7-16 Hazard Tool; however, the value for Boise, Idaho was based on data from ASCE 7-10 because data from ASCE 7-16 was unavailable. The ground snow load for case study areas assumed 50 pounds per square foot. The baseline was the approximate average ground snow load for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for tsunami loading is based on ASCE 7-16 methodology and an article published by *The Seattle Times* regarding the cost implications of incorporating tsunami-resistant features into the first building designed using the methodology. The environmental location factor included tsunami effects for one location: Seattle, Washington.

[1] Determined using the web interface on https://seismicmaps.org/. The Structural Engineers Association of California's and California's Office of Statewide Health Planning and Development developed this web interface that uses the open source code provided by the United States Geological Survey to retrieve the seismic design data. This website does not perform any calculations to the table values.

Additional Location Factor Considerations

Base costs for the thermal power cases were determined assuming no significant constraints with respect to available water resources, wastewater discharge requirements, and ambient temperature extremes. In areas where these constraints are expected to add significantly to the installed equipment, we applied location adjustments to the capital costs. To account for locations with limited water resources, such as California, the southwest, and the mountain west regions, air-cooled condensers are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place to reduce wastewater such as air-cooled condensers or cooling tower blowdown treatment systems.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. Costs for boiler enclosures are applied to the coal-fired cases and the biomass cases, but not to the CC heat recovery steam generators, which are assumed to open in all regions. It is assumed that the steam turbine generator (STG) equipment will be enclosed for all cases in all locations.

OPERATING & MAINTENANCE COST ESTIMATING

Once a plant enters commercial operation, the plant owners incur fixed O&M as well as variable O&M costs each year. Operations and maintenance costs presented in this report are non-fuel related.

Fixed O&M costs include costs directly related to the equipment design including labor, materials, contract services for routine O&M, and administrative and general costs. Not included are other fixed operating costs related to the location, notably property taxes and insurance. Labor, maintenance, and minor repairs and general and administrative (G&A) costs were estimated based on a variety of sources including actual projects, vendor publications, and Sargent & Lundy's internal resources. Variable O&M costs, such as ammonia, water, and miscellaneous chemicals and consumables, are directly proportional to the plant generating output.

Fixed O&M

Fixed O&M costs are those incurred at a power plant which do not vary with generation. Fixed O&M typically includes the following expenses:

- Routine Labor
- Materials and Contract Services
- Administrative and General Expenses

Routine labor includes the regular maintenance of the equipment as recommended by the equipment manufacturers. This includes maintenance of pumps, compressors, transformers, instruments, controls, and valves. The power plant's typical design is such that routine labor activities do not require a plant outage.

Materials and contract services include the materials associated with the routine labor as well as contracted services such as those covered under a long-term service agreement, which has recurring monthly payments.

General and administrative expenses are operation expenses, which include leases, management salaries, and office utilities.

For the hydro, solar, wind, and battery energy storage cases, all O&M costs are treated as fixed costs.

Variable O&M

Variable O&M costs are generation-based costs that vary based on the amount of electrical generation at the power plant. These expenses include water consumption, waste and wastewater discharge, chemicals such as selective catalytic reduction ammonia, and consumables including lubricants and calibration gas.

Cases

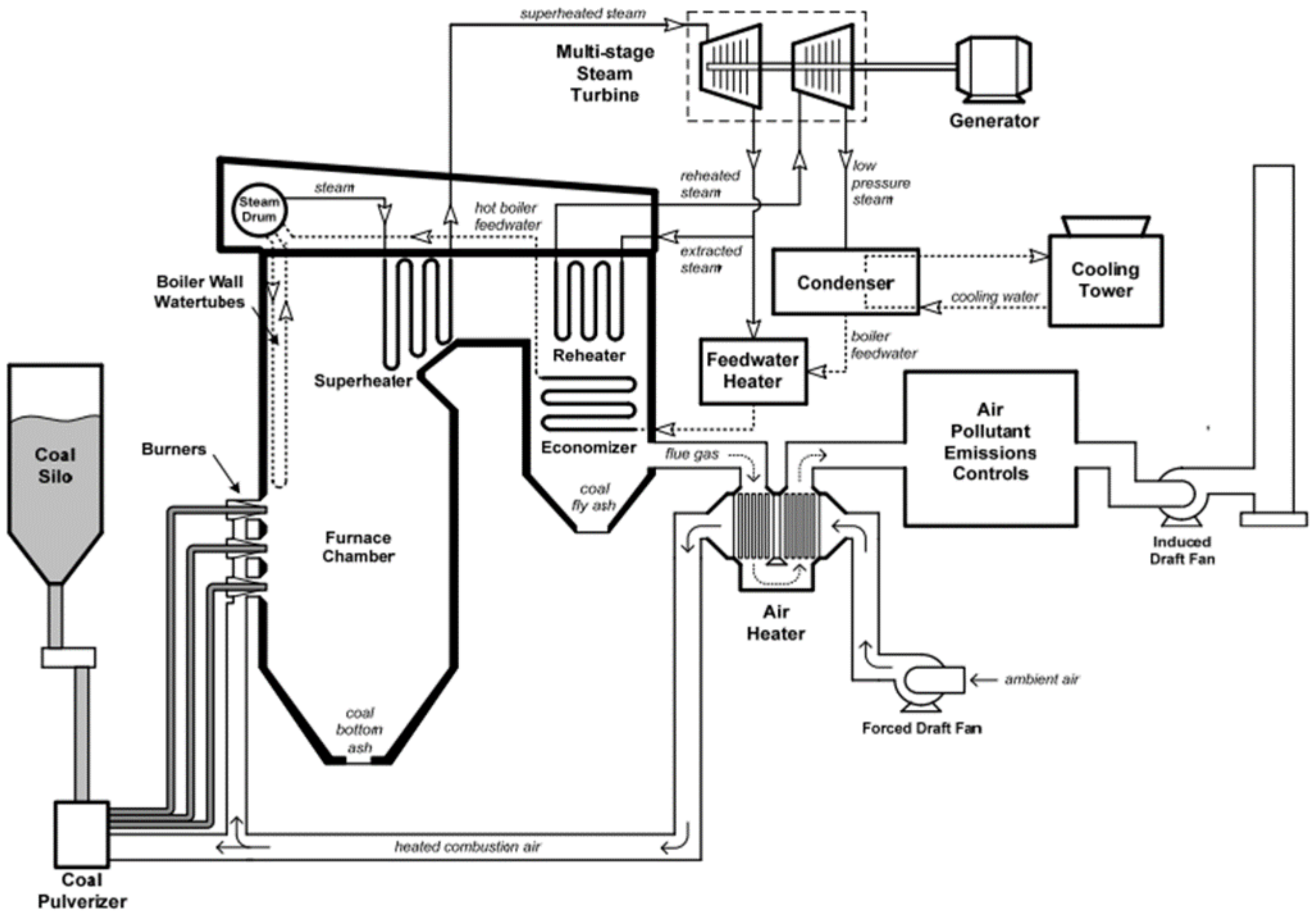
CASE 1. ULTRA-SUPERCRITICAL COAL WITHOUT CO_2 CAPTURE, 650 MW

1.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 megawatts (MW) with a single steam generator and steam turbine with coal storage and handling systems, balance-of-plant (BOP) systems, and emissions control systems; there are no carbon dioxide (CO_2) capture systems. This case employs a modified Rankine cycle, referred to as an ultra-supercritical (USC) thermal cycle, which is characterized by operation at supercritical pressures at approximately 3750 psia[2] and at steam temperatures above 1100°F (degrees Fahrenheit). This increase in steam pressure and steam temperature provides more energy per pound of fuel that can be converted to shaft power in the steam turbine. The USC steam cycles are a significant improvement from the more common subcritical cycles. USC technology, therefore, represents the most efficient steam cycle currently available. These higher efficiency boilers and turbines require less coal and consequently produce less greenhouse gases and lower emissions. Throughout the past decade, many USC coal plants have been placed in operation, although most of these facilities have been constructed in Europe and Asia. Figure 1-1 is a view of the first U.S. USC coal facility, which began operation in 2012.

[2] Pounds per square inch absolute

Figure 1-1 — USC Coal Boiler – Flow Diagram



Source: U.S. Environmental Protection Agency,
Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units PDF
Accessed from EPA.gov, https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf (accessed on July 8, 2019).

The base configuration used for the cost estimate is a single unit station constructed on a greenfield site of approximately 300 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal (approximately 4 MMBtu/hour SO_2) with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

1.1.1 Mechanical Equipment & Systems

1.1.1.1 USC Steam Cycle

The steam turbine is a tandem compound reheat machine consisting of a high-pressure turbine, an intermediate-pressure turbine, and two double-flow low-pressure turbines with horizontal casing splits. The USC thermal cycle comprises eight feedwater heaters, with the eighth heater supplied with extraction steam from the high-pressure turbine. This heater configuration is commonly referred to as a "HARP" system, which is a Heater Above Reheat Point of the turbine steam flow path. Boiler feedwater is pressured with a single high-pressure boiler feedwater pump, which is driven with an electric motor. (For the larger boiler size described in the 90% carbon capture case [Case 3], the boiler feedwater pump is steam turbine driven, with the turbine exhaust directed to the low-pressure condenser). Steam leaves the boiler to a high-pressure steam turbine designed for the USC pressures and temperatures. Steam leaving the high-pressure turbine is reheated in the boiler and directed to the intermediate-pressure turbine. The low-pressure turbine sections are twin dual flow turbines. The condensers are multi-flow units, one per each dual flow low-pressure turbine, operated at 2.0 inches of mercury absolute. The plant cooling system uses mechanical draft cooling towers with a circulated water temperature rise of 20°F.

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, and sea level elevation. The boiler efficiency is assumed to be 87.5%. The gross plant output is estimated to be 735 MW with a net output of 650 MW. The net heat rate is estimated to be 8638 Btu/kWh (British thermal unit per kilowatt hour) based on the higher heating value (HHV) of the fuel and the net electrical output.

1.1.1.2 Steam Generator

For the base case design, the single steam generator is designed for an outdoor location. The steam generator is a USC, pulverized-coal-fired type, balanced draft, once-through unit equipped with superheater, reheater, economizer, and regenerative air heaters. All materials of construction are selected to withstand the pressures and temperatures associated with the USC conditions are in accordance with Section 1 of the ASME BPVC. The boiler is fired with pulverized bituminous coal through six pulverizers. The boiler-firing system consists of low-nitrogen oxide (NO_X) burners (LNBs) and overfire air (OFA). A submerged flight conveyor system is used for bottom ash removal. An economizer preheats the feedwater prior to entering the boiler water walls. Combustion air is preheated with two parallel trisector air preheaters. Combustion air is delivered to the boiler by two forced draft fans and two primary air fans. Two axial induced draft fans are used to transfer combustion gases through a baghouse, wet flue gas desulfurization (WFGD) system, and wet chimney.

1.1.1.3 Water Treatment

The facility's water treatment plant consists of pretreatment and demineralization. All raw water entering the facility is first sent to the pretreatment system, which mainly consists of two redundant clarifiers where chemicals are added for disinfection and suspended solids removal. The pretreatment system includes lime addition, allowing for the partial removal of hardness and alkalinity from the raw water if required. After pretreatment, the water is sent to a storage tank and then directed to the service and firewater users. A demineralizer system is used to provide steam cycle makeup water of sufficient quality for the once-through system. All wastewater from the demineralizer system is either recycled to the WFGD system or sent to the wastewater neutralization and discharge system.

1.1.1.4 Material Handling

The coal handling system includes rail car unloading, reclaim systems, dual coal conveyor system, transfer towers, and coal crushers. The fly ash handling system includes equipment to remove ash from the boiler, economizer, air heater, and baghouse. Fly ash is collected dry and conveyed to a storage silo. Fly ash is collected from the storage by truck for offsite disposal.

1.1.2 Electrical & Control Systems

The USC facility generator is rated at approximately 780 megavolt-ampere (MVA) with an output of 24 kilovolts (kV) and is connected via generator circuit breakers to a generator step-up transformer (GSU). The GSU increases the voltage from the generator voltage level to the transmission system high-voltage level. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central distributed control system (DCS).

1.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 4600 tons per day. The approximate number of rail cars to support this facility is estimated at approximately 330 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The total volume of water required for cooling tower makeup, cycle makeup, and other demands is estimated to be approximately 7,000 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The facility is assumed to start up on natural gas; therefore, the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

1.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $3676/kilowatt (kW). Table 1-1 summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed, and no special systems are needed to prevent freezing or to account for snow loads on structures.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California, the southwest and the mountain west regions, air-cooled condensers (ACCs) are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the STG equipment will be enclosed in all locations.

Table 1-1 — Case 1 Capital Cost Estimate

Case 1 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net Ultra-Supercritical Coal w/o Carbon Capture – Greenfield** 1 x 735 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	8638	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		235,200,000
Mechanical – Boiler Plant	$	905,100,000	
Mechanical – Turbine Plant	$	155,200,000	
Mechanical – Balance of Plant	$	19,300,000	
Mechanical Subtotal	$		1,079,600,000
Electrical – Main Power System	$	18,100,000	
Electrical – Aux Power System	$	22,800,000	
Electrical – BOP and I&C	$	104,900,000	
Electrical – Substation and Switchyard	$	15,100,000	
Electrical Subtotal	$		160,900,000
Project Indirects	$		323,200,000
EPC Total Before Fee	$		1,798,900,000
EPC Fee	$		179,890,000
EPC Subtotal	$		1,978,790,000

Case 1 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**650 MW Net Ultra-Supercritical Coal w/o Carbon Capture – Greenfield** 1 x 735 MW Gross
Combustion Emissions Controls		Low NOx Burners / OFA
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP
Fuel Type		High Sulfur Bituminous
	Units	
Owner's Cost Components (Note 2)		
Owner's Services	$	138,515,000
Land	$	9,000,000
Electrical Interconnection	$	2,520,000
Gas Interconnection	$	4,850,000
Owner's Cost Subtotal	$	154,885,000
Project Contingency	$	256,041,000
Total Capital Cost	**$**	2,389,716,000
	$/kW net	**3,676**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

1.3 O&M COST ESTIMATE

The operating and maintenance costs for the USC coal-fired power generation facility are summarized in Table 1-2. The fixed costs cover the operations and maintenance (O&M) labor, contracted maintenance services and materials, and general and administrative (G&A). Major overhauls for the facility are generally based on a three-year/six-year basis depending on the equipment. Major steam turbine maintenance work is generally performed on a five- to six-year cycle, while shorter outages (e.g., change out selective catalytic reduction [SCR] catalyst) are generally performed on a three-year cycle.

Non-fuel variable costs for this technology case include flue gas desulfurization (FGD) reagent costs, SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, and FGD waste disposal costs.

Table 1-2 — Case 1 O&M Cost Estimate

Case 1 EIA – Non-Fuel O&M Costs – 2019 $S		
650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield		
Fixed O&M – Plant (Note 1)		
Labor	$/year	15,317,000
Materials and Contract Services	$/year	7,830,000
Administrative and General	$/year	3,233,000
Subtotal Fixed O&M	$/year	26,380,000
$/kW-year	$/kW-year	**40.58 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.50 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

1.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 1-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.06 pounds per one million British thermal units (lb/MMBtu). The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu. The CO_2 emissions estimates are based on the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 1-3 — Case 1 Emissions

Case 1 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture – Greenfield		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	206 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal		
2. NOx Removal using LNBs with OFA, and SCR		
3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction		
4. Per 40 CFR 98, Subpt. C, Table C-1		

The post-combustion environmental controls for this technology case include an SCR NO_X system with aqueous ammonia as the reagent, a fabric-filter baghouse ash collection system with pulse jet cleaning, and a limestone-based forced-oxidation WFGD for the removal of SO_2 and sulfur trioxide. A wet electrostatic precipitator is included to mitigate sulfuric acid emissions. The flue gas pressure drops incurred from these backend controls have been accounted for in the induced draft fan sizing and the resultant auxiliary power demands in addition to the auxiliary power demands for the emissions control systems themselves.

For this case, no CO_2 emissions controls are assumed to be applicable. Please refer to Case 2 for 30% carbon capture and Case 3 for 90% carbon capture.

CASE 2. ULTRA-SUPERCRITICAL COAL WITH 30% CO_2 CAPTURE, 650 MW

2.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 MW with a single steam generator and steam turbine with coal storage and handling systems, BOP systems, emissions control systems, and a 30% CO_2 capture system. This technology case is similar to the plant description provided in Case 1; however, this case employs CO_2 capture systems that require a larger boiler size and higher heat input to account for the low-pressure steam extraction and larger auxiliary loads needed for the CO_2 capture technology used. The CO_2 capture systems are commonly referred to as carbon capture and sequestration system (CCS) systems; however, for the cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed to be compressed to supercritical conditions and injected into a pipeline terminated at the fence line of the facility. For this report, the terms “CO_2 capture” and “carbon capture” are used interchangeably.

As with Case 1, the base configuration used for the cost estimate is a single-unit station constructed on a greenfield site of approximately 300 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

2.1.1 Mechanical Equipment & Systems

Refer to Case 1 for a description of the major mechanical equipment and systems associated with the USC power generation facility. This section provides a description of the major CO_2 capture systems used as the basis for the capital and O&M cost estimates.

2.1.1.1 General CO_2 Capture Description

The most commercially available CO_2 capture technology for coal-fired power plants is amine-based scrubbing technology. This technology requires an absorption column to absorb the CO_2 from the flue gas and a stripping column to regenerate the solvent and release the CO_2. Amine-based solvents are used in the absorption column and require periodic makeup streams and waste solvent reclamation. Steam is used to break the bond between the CO_2 and solvent. CO_2 leaves the stripper with moisture prior to being dehydrated and compressed. The product CO_2 is pipeline quality at 99.5% purity and approximately 2215 psia. The amine-based solvent systems are typically designed for 90% CO_2 capture in the absorption column.

2.1.1.2 CO_2 Capture Systems

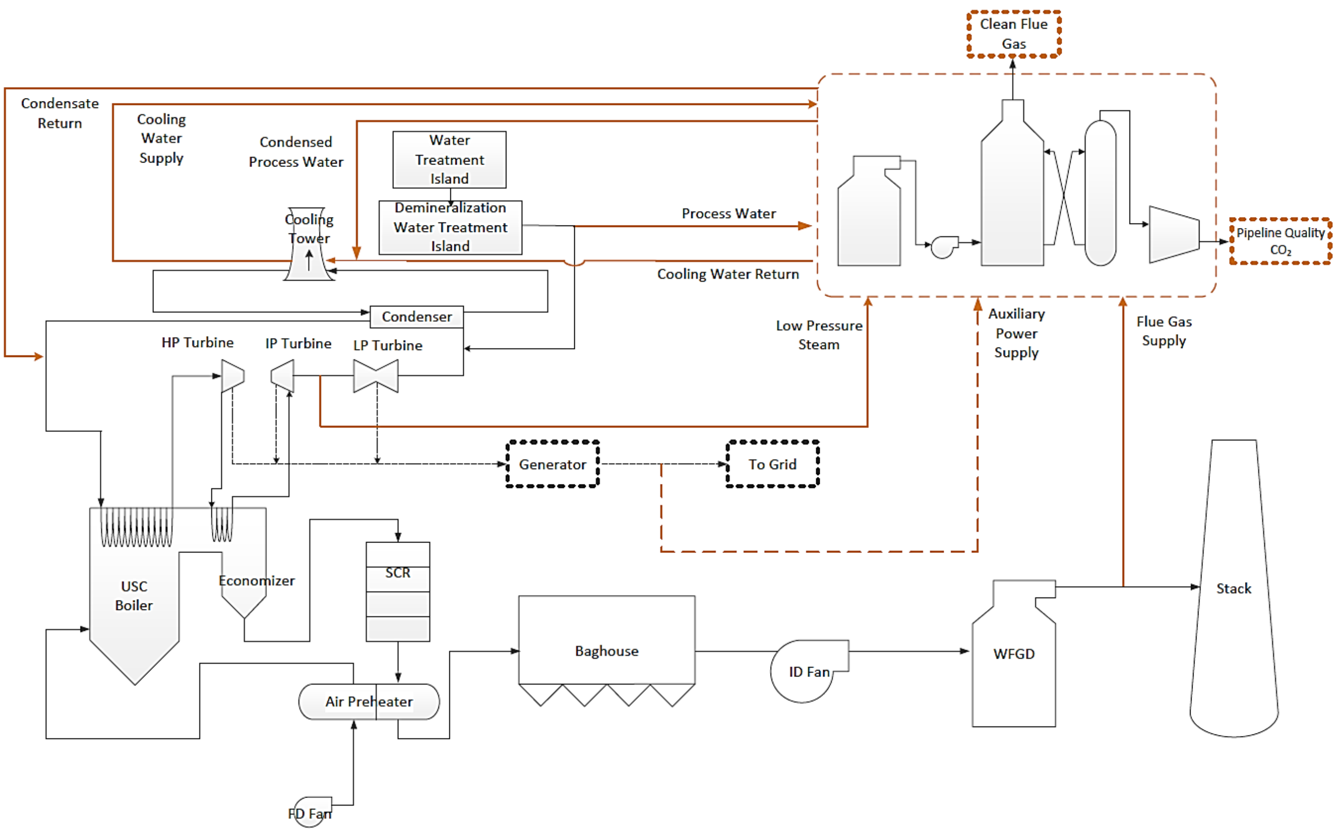
This case assumes being built with full integration to the CO_2 capture facility. The CO_2 capture technology uses various utilities to operate, including low-quality steam and auxiliary power. Steam can be extracted between the intermediate pressure and low-pressure turbine sections that will provide the least amount of capacity derate while maintaining the necessary energy to drive the CO_2 capture system. Extracting steam prior to the low-pressure turbine section requires additional fuel to be fired to account for the lost generation potential. As such, the boiler, turbine, and associated systems would be required to be made larger to maintain the same net power production. Additionally, the CO_2 capture facility and BOP associated with the CO_2 capture system requires a significant amount of auxiliary power to drive the mechanical equipment. Most of the power consumption is used to drive the CO_2 compressors to produce pipeline quality CO_2 at approximately 2215 psia. The increase in auxiliary power consumption due to the CO_2 facility usage will require a larger turbine throughput to produce the added output. Overall, CO_2 capture system integration can account for a net derate of approximately 30% in comparison with the base facility power output.

Other utilities that are integrated with the base plant are demineralized water and cooling water. Demineralized water is used to maintain a water balance within the amine process or in the solvent regeneration stages. The demineralized water consumption rate for the CO_2 capture facility is typically minor in comparison with base-plant utilization rates. As such, the demineralized water is expected to be fed from the base facility. This cost is accounted for in the O&M estimate only. Conversely, cooling water demands for the carbon capture process is significant. CO_2 capture systems require circulating cooling water rates similar to that of the condensers. As such, the cooling system, in this case evaporative cooling towers, are required to be expanded to account for the large amount of additional heat rejection. This cost is accounted for in the capital and O&M estimates. The increase in cooling tower size also requires a higher cooling tower blowdown rate that needs to be treated at the wastewater treatment system. This cost is reflected in the capital and O&M estimates.

Commercial amine-based CO_2 capture technology requires a quencher to be located upstream of the CO_2 absorber vessel. The quencher is used to cool the flue gas to optimize the kinetics and efficiency of the CO_2 absorption process via the amine-based solvent. During the quenching process, a significant amount of flue gas moisture condenses into the vessel and requires a significant amount of blowdown to maintain the level in the vessel. This blowdown quality is not good enough to reuse in the absorber system for water balance, but it is an acceptable quality to either reuse in the cooling towers or WFGD for makeup water. Due to the reuse, it does not require additional O&M costs.

A generic flow diagram for post-combustion carbon capture system is provided in Figure 2-1. The termination of the process of the CO_2 capture facility is the new emissions point, which is a small stack at the top of the CO_2 absorber vessel. For this configuration, a typical free-standing chimney is not required. Additionally, the compressed product CO_2 is the other boundary limit. This estimate does not include pipeline costs to transport the CO_2 to a sequestration or utilization site.

Figure 2-1 — Carbon Capture Flow Diagram



2.1.1.3 30% CO_2 Capture

For this technology case, the USC coal-fired facility is required to provide 30% CO_2 reduction; approximately one-third of the total flue gas must be treated. As referenced previously, 90% capture is the typical design limit for CO_2 reduction in the absorber. Therefore, 33% of the plant's flue gas would need to be treated to provide 90% reduction efficiency. A slipstream of the flue gas downstream of the

WFGD system would be extracted and sent to the CO_2 capture island. The remaining flue gas would exit through a typical free-standing wet chimney.

In this scenario, a significant amount of steam and auxiliary power is required to drive the large CO_2 capture system, ultimately increasing the size of the boiler to generate the additional steam and power required to maintain a net power output of 650 MW. As the boiler gets larger, more flue gas must be treated. As such, it is an iterative process to determine the new boiler size necessary to treat 33% of the flue gas from a new USC coal-fired boiler. Ultimately, the boiler would be built with a larger heat input than the non-CO_2 capture cases; however, the increase in size would be much less than the 90% capture case.

2.1.1.4 Plant Performance

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, sea level elevation, and 30% CO_2 capture. Approximately 790,000 pound per hour of low-pressure steam is required for the CO_2 system. While the boiler efficiency is assumed to be 87.5%, the estimated gross size of the steam generator is approximately 827 MW, which is approximately 13% larger than the case without carbon capture (Case 1). The estimated total auxiliary load for the plant is 119.5 MW with 28 MW required for the CO_2 system. The net heat rate is estimated to be 9751 Btu/kWh based on the HHV of the fuel and the net electrical output.

2.1.2 Electrical & Control Systems

The electrical equipment includes the turbine generator, which connects via generator circuit breakers to a GSU. The GSU increases the voltage from the generator voltages level to the transmission system high-voltage level. The electrical system is essentially similar to the USC case without carbon capture (Case 1); however, there are additional electrical transformers and switchgear for the CO_2 capture systems. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central DCS.

2.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 5200 tons per day. The approximate number of rail cars to support this facility is estimated at approximately 360 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The estimated total volume of water required for cooling tower makeup, cycle makeup, and cooling for the CO_2 system is approximately 10,000 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The CO_2 captured will need to be sequestered in a geologic formation or used for enhanced oil recovery. The viability of this technology case will be driven, to a large extent, by the proximity of the facility to appropriate geologic formations. The costs presented herein do not account for equipment, piping, or structures associated with CO_2 sequestration.

The facility is assumed to start up on natural gas; therefore, the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

2.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $4558/kW. Table 2-1 summarizes the cost components for this case. Cost associated with CO_2 sequestration have been excluded. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed. No special systems are needed to prevent freezing or to account for snow loads on structures.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California and the southwest and the mountain west regions, ACCs are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, ZLD equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the STG equipment will be enclosed in all locations.

Table 2-1 — Case 2 Capital Cost Estimate

Case 2 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture** 1 x 769 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP - AMINE Based CCS	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	9751	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		263,200,000
Mechanical – Boiler Plant	$	935,766,667	
Mechanical – Turbine Plant	$	185,866,667	
Mechanical – Balance of Plant	$	49,966,667	
Mechanical Subtotal	$		1,171,600,000

Case 2 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture** 1 x 769 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP - AMINE Based CCS	
Fuel Type		High Sulfur Bituminous	
	Units		
Electrical – Main Power System	$	21,100,000	
Electrical – Aux Power System	$	25,800,000	
Electrical – BOP and I&C	$	107,900,000	
Electrical – Substation and Switchyard	$	18,100,000	
Electrical Subtotal	$		172,900,000
CCS Plant Subtotal	$		278,752,000
Project Indirects	$		347,200,000
EPC Total Before Fee	$		2,233,652,000
EPC Fee	$		223,365,200
EPC Subtotal	$		2,457,017,200
Owner's Cost Components (Note 2)			
Owner's Services	$		171,991,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000
Owner's Cost Subtotal	$		188,361,000
Project Contingency	$		317,445,000
Total Capital Cost	**$**		2,962,823,200
	$/kW net		**4,558**
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			

2.3 O&M COST ESTIMATE

The O&M costs for the USC coal-fired power generation facility with 30% carbon capture are summarized in Table 2-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and G&A. Major overhauls for the facility are generally based on a three-year/six-year basis depending on the equipment. Major steam turbine maintenance work is generally performed on a five- to six-year cycle, while shorter outages (e.g., change out SCR catalyst) are generally performed on a three-year cycle. It is assumed that the carbon capture equipment would have major overhauls on a three-year cycle, but there is not a sufficient operating base to confidently predict the required frequency of major maintenance. The carbon capture equipment will require additional O&M labor. It is assumed that some type of service agreement would be needed for the compressors, absorbers, strippers, and other specialized equipment.

Non-fuel variable costs for this technology case include FGD reagent costs, SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, FGD waste disposal costs, and solvent makeup. For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly combustion turbine [CT] blowdown treatment), and additional demineralized makeup water costs.

Table 2-2 — Case 2 O&M Cost Estimate

Case 2 EIA – Non-Fuel O&M Costs – 2019 $s		
650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Labor	$/year	18,177,000
Materials and Contract Services	$/year	10,959,000
Administrative and General	$/year	6,156,000
Subtotal Fixed O&M	$/year	35,292,000
$/kW-year	$/kW-year	**54.30 $/kW-year**
Variable O&M (Note 2)	$/MWh	**7.08 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

2.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 2-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.06 lb/MMBtu. The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu. The CO_2 emissions estimates are based on a 30% removal from the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 2-3 — Case 2 Emissions

Case 2 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	144 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal		
2. NOx Removal using LNBs with OFA, and SCR		
3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction		
4. 30% reduction from baseline Per 40 CFR 98, Subpt. C, Table C-1		

CASE 3. ULTRA-SUPERCRITICAL COAL WITH 90% CO_2 CAPTURE, 650 MW

3.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 MW with a single steam generator and ST with coal storage and handling systems, BOP systems, emissions control systems, and a 90% CO_2 capture system. This case is similar to the plant description provided in (Case 1) and (Case 2); however, this case employs 90% CO_2 capture system for the entire flue gas stream, which requires a larger boiler size and higher heat input to account for the low-pressure steam extraction and larger auxiliary loads needed for the CO_2 capture technology used. The steam cycle is generally similar to the UCS cases with carbon capture; however, the boiler feedwater pumps are steam driven as opposed to motor driven.

The CO_2 capture systems are commonly referred to as CCS systems; however, for the cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed compressed to supercritical conditions and injected into a pipeline at terminated at the fence line of the facility. For this report, the terms “CO_2 capture” and “carbon capture” are used interchangeably.

As with Case 1 and Case 2, the base configuration used for the cost estimate is a single-unit station constructed on a greenfield site of approximately 300 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal (approximately 4 MMBtu/hour SO_2) with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

3.1.1 Mechanical Equipment & Systems

Refer to Case 1 for a description of the major mechanical equipment and systems associated with the USC power generation facility. This section provides a description of the major CO_2 capture systems used as the basis for the capital and O&M cost estimates.

3.1.1.1 General CO_2 Capture Description

The most commercially available CO_2 capture technology for coal-fired power plants is amine-based scrubbing technology. This technology requires an absorption column to absorb the CO_2 from the flue gas and a stripping column to regenerate the solvent and release the CO_2. Amine-based solvents are used in the absorption column and require periodic makeup streams and waste solvent reclamation. Steam is used to break the bond between the CO_2 and solvent. CO_2 leaves the stripper with moisture prior to being dehydrated and compressed. The product CO_2 is pipeline quality at 99.5% purity and approximately 2215 psia. The amine based solvent systems are typically designed for 90% CO_2 capture in the absorption column. Please refer to Figure 2-1 for simplified process flow diagram of the CO_2 capture system.

3.1.1.2 CO_2 Capture Systems

It is assumed that this case will be built with full integration to the CO_2 capture facility. The CO_2 capture technology uses various utilities to operate, including low-quality steam and auxiliary power. Steam can be extracted between the intermediate-pressure and low-pressure turbine sections, which will provide the least amount of capacity derate, while maintaining the necessary energy to drive the CO_2 capture system. Extracting steam prior to the low-pressure turbine section requires additional fuel to be fired to account for the lost generation potential. As such, the boiler turbine would be required to be made larger to maintain the same net power production. Additionally, the CO_2 capture facility and BOP associated with the CO_2 capture system requires a significant amount of auxiliary power to drive the mechanical equipment. Most of the power consumption is used to drive the CO_2 compressor to produce pipeline-quality CO_2 at approximately 2215 psia. The increase in auxiliary power consumption due to the CO_2 facility usage will require a larger turbine throughput to produce the added output. Doing so requires a larger boiler or turbine to maintain the same net power output of the facility. Overall, CO_2 capture system integration can account for a net derate of approximately 30% in comparison with the base facility power output.

Other utilities that are integrated with the base plant are demineralized water and cooling water. Demineralized water is used to maintain a water balance within the amine process or in the solvent regeneration stages. The demineralized water consumption rate for the CO_2 capture facility is typically minor in comparison with base-plant utilization rates. As such, the demineralized water is expected to be fed from the base facility. This cost is accounted for in the O&M estimate only. Conversely, Cooling water is not a minor flow rate. CO_2 capture systems can require similar circulating cooling water rates as condensers themselves. As such, the cooling system (in this case, evaporative cooling towers) are required to be expanded to account for the large amount of additional heat rejection. This cost is accounted for in the capital and O&M estimates. The increase in cooling tower size also requires a higher cooling tower blowdown rate that needs to be treated at the wastewater treatment system. This cost is reflected in the capital and O&M estimates.

Commercial amine-based CO_2 capture technology requires a quencher to be located upstream of the CO_2 absorber vessel. The quencher is used to cool the flue gas to optimize the kinetics and efficiency of the CO_2 absorption process via the amine-based solvent. During the quenching process, a significant amount of flue gas moisture condenses into the vessel. This requires a significant amount of blowdown to maintain the level in the vessel. This blowdown quality is not good enough to reuse in the absorber system for water balance, but it is an acceptable quality to either reuse in the cooling towers or WFGD for makeup water. Due to the reuse, it does not require additional O&M costs.

A generic flow diagram for post-combustion carbon capture system is provided in Figure 2-1. The termination of the process of the CO_2 capture facility is the new emissions point, which is a small stack at the top of the CO_2 absorber vessel. For this configuration, a typical free-standing chimney is not required. Additionally, the compressed product CO_2 is the other boundary limit. This estimate does not include pipeline costs to transport the CO_2 to a sequestration or utilization site.

3.1.1.3 90% CO_2 Capture

For the case where a new USC coal-fired facility is required to provide 90% CO_2 reduction, the full flue gas path must be treated. As referenced previously, 90% capture is the typical design limit for CO_2 reduction in the absorber. Therefore, 100% of the plant's flue gas would need to be treated to provide 90% reduction efficiency. In this scenario, a significant amount of steam and auxiliary power is required to drive the large CO_2 capture system, ultimately increasing the size of the boiler to generate the additional steam and power required to maintain a net power output of 650 MW. As the boiler gets larger, more flue gas must be treated. As such, it is an iterative process to determine the new boiler size necessary to treat 100% of the flue gas from a new USC coal-fired boiler.

3.1.1.4 Plant Performance

For this case, all the flue gas is discharged from the carbon capture system, so no additional wet chimney is included in the capital cost estimate.

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, sea level elevation, and 90% CO_2 capture. Approximately 2,370,000 lb/hr of low-pressure steam is required for the CO_2 system. While the boiler efficiency is assumed to be 87.5%, the estimated gross size of the steam generator is approximately 1,054 MW, which is approximately 40% larger than the case without carbon capture (Case 1). The estimated total auxiliary load for the plant is 181 MW, with 118 MW required for the for the CO_2 system. The net heat rate is estimated to be 12507 Btu/kWh based on the HHV of the fuel and the net electrical output.

3.1.2 Electrical & Control Systems

The electrical equipment includes the turbine generator, which is connected via generator circuit breakers to a GSU. The GSU increases the voltage from the generator voltage level to the transmission system high-voltage level. The electrical system is essentially similar to the USC case without carbon capture (Case 1); however, there are additional electrical transformers and switchgear for the CO_2 capture systems. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central DCS.

3.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 6700 tons per day. The number of rail cars to support this facility is estimated at approximately 470 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The total volume of water required for cooling tower makeup, cycle makeup, and cooling for the CO_2 system is estimated to be approximately 17,000 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The CO_2 captured will need to be sequestered in a geologic formation or used for enhanced oil recovery. The viability of this technology case will be driven, to a large extent, by the proximity of the facility to the appropriate geologic formations. The costs presented herein do not account for equipment, piping, or structures associated with CO_2 sequestration.

The facility is assumed to start up on natural gas, therefore the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

3.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $5876/kW. Table 3-1 summarizes the cost components for this case. Cost associated with CO_2 sequestration have been excluded. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed. No special systems are needed to prevent freezing or to account for snow loads on structures.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water, and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California and the southwest and the mountain west regions, ACCs are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, ZLD equipment is added. Zero liquid discharge wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the STG equipment will be enclosed in all locations.

Table 3-1 — Case 3 Capital Cost Estimate

Case 3 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture** 1 x 831 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	12507	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	15%	
Owner's Services	% of Project Costs	5%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		311,200,000
Mechanical – Boiler Plant	$	967,433,333	
Mechanical – Turbine Plant	$	242,533,333	
Mechanical – Balance of Plant	$	92,077,778	
Mechanical Subtotal	$		1,302,044,444
Electrical – Main Power System	$	26,350,000	
Electrical – Aux Power System	$	31,050,000	
Electrical – BOP and I&C	$	113,150,000	
Electrical – Substation and Switchyard	$	23,350,000	
Electrical Subtotal	$		193,900,000
CCS Plant Subtotal	$		663,846,000
Project Indirects	$		390,200,000
EPC Total Before Fee	$		2,861,190,000
EPC Fee	$		286,119,000
EPC Subtotal	$		3,147,309,000
Owner's Cost Components (Note 2)			
Owner's Services	$		157,365,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000

Case 3 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture** 1 x 831 MW Gross
Combustion Emissions Controls		Low NOx Burners / OFA
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%
Fuel Type		High Sulfur Bituminous
	Units	
Owner's Cost Subtotal	$	173,735,000
Project Contingency	$	498,157,000
Total Capital Cost	**$**	3,819,201,000
	$/kW net	**5,876**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

3.3 O&M COST ESTIMATE

The O&M costs for the USC coal-fired power generation facility with 90% carbon capture are summarized in Table 3-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and G&A. Major overhauls for the facility are generally based on a three-year/six-year basis depending on the equipment. Major steam turbine maintenance work is generally performed on a five- to six-year cycle, while shorter outages (e.g., change out SCR catalyst) are generally performed on a three-year cycle. It is assumed that the carbon capture equipment would have major overhauls on a three-year cycle, but there is not a sufficient operating base to confidently predict the required frequency of major maintenance. The carbon capture equipment will require additional O&M labor. It is assumed that some type of service agreement would be needed for the compressors, absorbers, strippers, and other specialized equipment.

Non-fuel Variable costs for this technology case include FGD reagent costs, SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, FGD waste disposal costs, and solvent makeup. For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs.

Table 3-2 — Case 3 O&M Cost Estimate

Case 3 EIA – Non-Fuel O&M Costs – 2019 $s		
650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Labor	$/year	18,817,000
Materials and Contract Services	$/year	12,051,000
Administrative and General	$/year	7,836,000
Subtotal Fixed O&M	$/year	38,704,000
$/kW-year	$/kW-year	**59.54 $/kW-year**
Variable O&M (Note 2)	$/MWh	**10.98 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

3.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 3-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.06 lb/MMBtu. The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu. The CO_2 emissions estimates are based on a 90% removal from the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 3-3 — Case 3 Emissions

Case 3 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	20.6 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal 2. NOx Removal using LNBs with OFA, and SCR 3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction 4. 90% reduction from baseline Per 40 CFR 98, Subpt. C, Table C-1		

CASE 4. INTERNAL COMBUSTION ENGINES, 20 MW

4.1 CASE DESCRIPTION

This case is a reciprocating internal combustion engine (RICE) power plant based on four large-scale natural-gas-fired engines. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW. The configuration is selected to represent the installation of peaking or supplemental capacity for a municipality or small utility.

4.1.1 Mechanical Equipment & Systems

The RICE power plant comprises four gas-fired engines that are coupled to a generator. The power plant also includes the necessary engine auxiliary systems, which are fuel gas, lubricated oil, compressed air, cooling water, air intake, and exhaust gas.

Each engine is comprised of 10 cylinders in a V configuration. The engines are a four-stroke, spark-ignited, single fuel engine that operates on the Otto cycle. Each engine includes a turbocharger with an intercooler that uses the expansion of hot exhaust gases to drive a compressor that raises the pressure and density of the inlet air to each cylinder, leading to increased power output of the engine. Each engine is equipped with an SCR and carbon monoxide (CO) catalyst for emissions control.

The engines are cooled using a closed-loop cooling water system that circulates a water/glycol mixture through the engine block. Heat is rejected from the cooling water system by air-cooled radiators. A starting air system provides the high-pressure compressed air required to start the engine. An instrument air system is provided for standard instrumentation and plant air use.

4.1.2 Electrical & Control Systems

The electrical generator is coupled to the engine. The generator is a medium voltage, air-cooled, synchronous alternating current (AC) generator.

The engine original equipment manufacturer (OEM) provides a DCS that allows for a control interface, plant operating data, and historian functionality. The control system is in an onsite building. Programmable logic controllers are also provided throughout the plant for local operation.

4.1.3 Offsite Requirements

Natural gas is delivered to the facility through a gas connection at the site boundary. A natural gas line is routed from the nearest gas lateral to a gas metering station at the site boundary. The gas pressure is reduced as necessary to meet the requirements of the facility downstream of the metering station.

Since water consumption is minimal at the power plant, water is obtained from the municipal water supply. The power plant also includes minimal water treatment for onsite water usage. Wastewater is treated using an oil-water separator and then is directed to a municipal wastewater system. Used oil that is no longer filterable is stored in a waste oil tank and removed offsite with a vacuum truck.

The power plant's onsite switchyard is connected to the transmission system through a nearby substation.

4.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1810/kW. Table 4-1 summarizes the cost components for this case.

Table 4-1 — Case 4 Capital Cost Estimate

Case 4 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Internal Combustion Engines** 4 x 5.6 MW
Combustion Emissions Controls		None
Post-Combustion Emissions Controls		SCR
Fuel Type		Natural Gas
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	21.4
Net Plant Heat Rate, HHV Basis	Btu/kWh	8295
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	8%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	$	10
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	720,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	100,000
Miles	miles	0.50
Metering Station	$	75,000

Case 4 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Internal Combustion Engines** 4 x 5.6 MW	
Combustion Emissions Controls		None	
Post-Combustion Emissions Controls		SCR	
Fuel Type		Natural Gas	
	Units		
Typical Project Timelines			
Development, Permitting, Engineering	months	12	
Plant Construction Time	months	18	
Total Lead Time Before COD	months	30	
Operating Life	years	30	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,861,000
Engines (Note 3)	$	11,974,000	
Mechanical BOP	$	5,521,000	
Mechanical Subtotal	$		17,495,000
Electrical Subtotal	$		6,668,000
Project Indirects	$		180,000
EPC Total Before Fee	$		19,230,000
EPC Fee	$		1,923,000
EPC Subtotal	$		21,153,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,586,000
Land	$		300,000
Owner Furnished Equipment (Note 3)	$		11,974,000
Electrical Interconnection	$		720,000
Gas Interconnection	$		125,000
Owner's Cost Subtotal	$		14,705,000
Project Contingency	$		2,869,000
Total Capital Cost	**$**		38,727,000
	$/kW net		**1,810**
Capital Cost Notes			

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.
3. Engines and associated auxiliaries procured by Owner from the engine OEM.

4.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 4-2 — Case 4 O&M Cost Estimate

Case 4 EIA – Non-Fuel O&M Costs – 2019 $s		
Internal Combustion Engines		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**35.16 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.69 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables.		

4.4 ENVIRONMENTAL & EMISSIONS INFORMATION

NO_X and CO emissions are maintained through an SCR and CO catalyst installed in the exhaust system of each engine. SO_2 is uncontrolled but minimal and below emission limits because of the low amounts of SO_2 in the natural gas fuel. Water, wastewater, solid waste, and spent lubricating oil are disposed of through conventional means.

Table 4-3 — Case 4 Emissions

Case 4 EIA – Emissions Rates		
Internal Combustion Engines		
Predicted Emissions Rates – Natural Gas		
NOx	lb/MMBtu	0.02 (Note 1)
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.03
CO_2	lb/MMBtu	117 (Note 2)
Emissions Control Notes		
1. With SCR		
2. Per 40 CFR98 Sub Part C – Table C1		

CASE 5. COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE

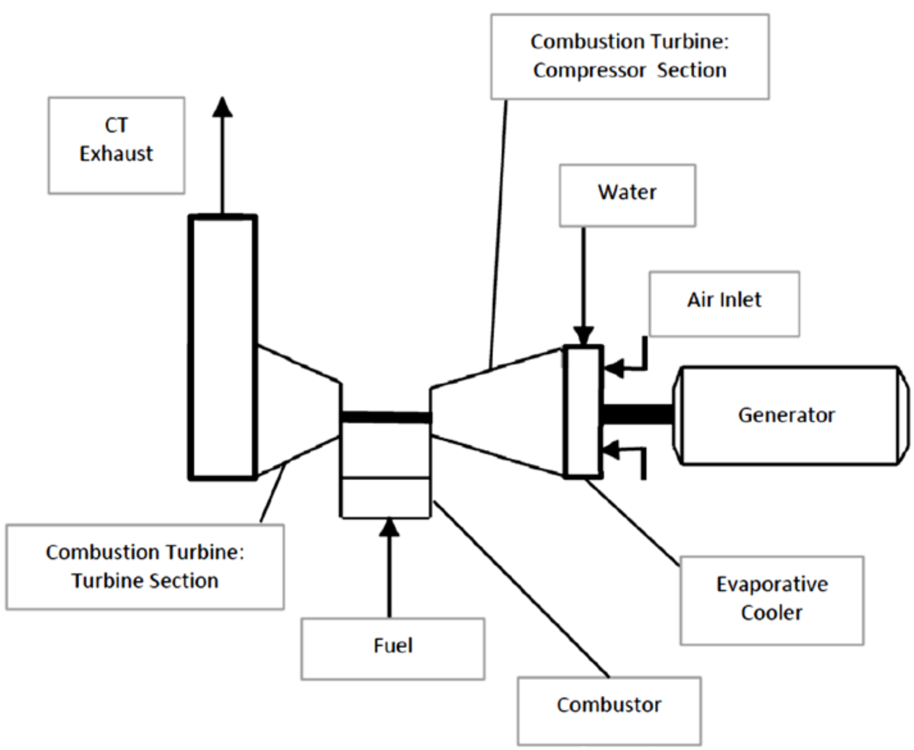
5.1 CASE DESCRIPTION

This case is comprised of two duplicate aeroderivative CTs in simple-cycle configuration. It is based on natural gas firing of the CTs, although dual fuel capability is provided. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

5.1.1 Mechanical Equipment & Systems

Case 5 is comprised of a pair of aeroderivative dual fuel CTs in simple-cycle configuration, with a nominal output of 53.7 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is 105.1 MW. Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also equipped with burners designed to reduce the CT's emission of NO_X. Not included in the Case 5 configuration are SCR units for further reduction of NO_X emissions or CO catalysts for further reduction of CO emissions. Refer to Figure 5-1 for a diagram of the CT systems.

Figure 5-1 — Case 2 Configuration



Note: Only one CT shown. Second CT has the same configuration.

Aeroderivative CTs differ from industrial frame CTs in that aeroderivative CTs have been adapted from an existing aircraft engine design for stationary power generation applications. Consequently, compared to industrial frame CTs of the same MW output, aeroderivative CTs are lighter weight, have a smaller size footprint, and have more advanced materials of construction. Additionally, aeroderivative CTs in general operate at higher pressure ratios, have faster start-up times and ramp rates, and higher efficiencies compared to industrial frame CTs.

5.1.2 Electrical & Control Systems

Case 5 includes one 60-hertz (Hz) electric generator per CT with an approximate rating of 54 MVA and output voltage of 13.8 kV. The generator output power is converted to a higher voltage by GSUs for transmission to the external grid transmitted via an onsite switchyard.

The simple-cycle facility is controlled by a control system provided by the CT manufacturer, supplemented by controls for the BOP systems (e.g., water supply to evaporative coolers, fuel supply).

5.1.3 Offsite Requirements

Offsite provisions in Case 5 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile long transmission line.
- **Water Supply for Evaporative Cooler and Miscellaneous Uses:** It is assumed that the water supply source, such as a municipal water system, is near the power plant site and the interconnection for water is at the plant’s site boundary. Blowdown waste from the evaporative cooler is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection’s location is assumed at the power plant’s site boundary.

5.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1175/kW. Table 5-1 summarizes the cost components for this case. This estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 5-1 covers owner’s costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 5-1 — Case 5 Capital Cost Estimate

Case 5 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Combustion Turbines – Simple Cycle** 2 x Aeroderivative Class	
Combustion Emissions Controls		Dry Low Emissions Combustor	
Post-Combustion Emissions Controls		None	
Fuel Type		Natural Gas / No. 2 Backup 2 x 54 MW rating	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	105	
Heat Rate, HHV Basis	Btu/kWh	9124	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	20	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	3,100,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,300,000
Mechanical – Major Equipment	$	43,400,000	
Mechanical – Balance of Plant	$	9,900,000	
Mechanical Subtotal	$		53,300,000
Electrical Subtotal	$		15,400,000
Project Indirects	$		15,000,000
EPC Total Before Fee	$		90,000,000
EPC Fee	$		9,000,000
EPC Subtotal	$		99,000,000
Owner's Cost Components (Note 2)			
Owner's Services	$		6,930,000
Land	$		600,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		4,500,000

Case 5 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Combustion Turbines – Simple Cycle** 2 x Aeroderivative Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		None
Fuel Type		Natural Gas / No. 2 Backup 2 x 54 MW rating
	Units	
Owner's Cost Subtotal	$	13,230,000
Project Contingency	$	11,223,000
Total Capital Cost	**$**	123,453,000
	$/kW net	**1,175**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

5.3 O&M COST ESTIMATE

Table 5-2 shows O&M costs. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CTs.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CTs over the long-term maintenance cycle, based on the number of equivalent operating hours (EOH) the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. The aeroderivative CTs in Case 5 always use an EOH-driven maintenance overhaul schedule regardless of the operating profile. Refer to Case 6 for a starts-based overhaul schedule.) An additional advantage of an aeroderivative CTs is that, depending on the long-term service agreement terms, sections of the CT can be changed out with replacement assemblies, reducing the outage time of major overhauls to less than one week (compared to more than a two-week outage for industrial frame CTs).

Table 5-2 — Case 5 O&M Cost Estimate

Case 5 EIA – Non-Fuel O&M Costs – 2019 $s		
Combustion Turbine – Simple Cycle		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**16.30 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.70 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water and water discharge treatment cost. They are based on a number operating hours-based regimen.		

5.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 5 simple-cycle configuration, NO_X emissions from the CT stacks when firing gas are indicated in Table 5-3. Although some locations in the United States would require SCRs and CO catalysts to further reduce stack emissions, SCRs and CO catalysts have not been included for Case 5.

Table 5-3 — Case 5 Emissions

Case 5 EIA – Emissions Rates		
Combustion Turbine – Simple Cycle		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.09
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 6. COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE

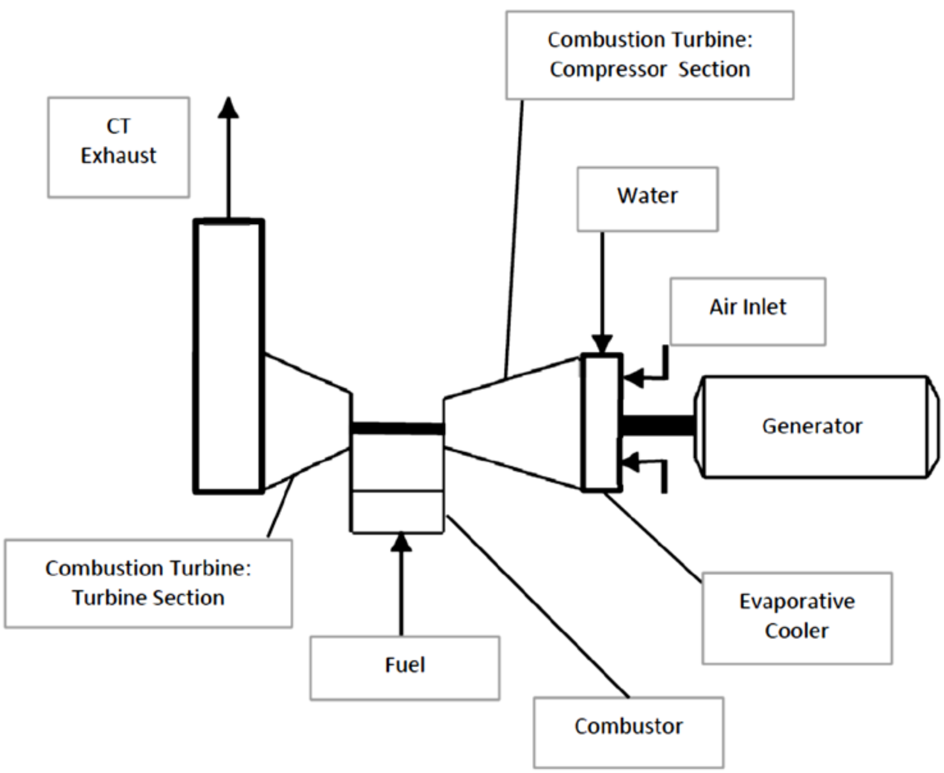
6.1 CASE DESCRIPTION

This case is comprised of one industrial frame Model F CT in simple-cycle configuration. It is based on natural gas firing of the CT, although dual fuel capability is provided. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

6.1.1 Mechanical Equipment & Systems

Case 6 is comprised of one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X. Not included in the Case 6 configuration is an SCR unit for further reduction of NO_X emissions or a CO catalyst for further reduction of CO emissions. Figure 6-1 shows a diagram of the CT systems.

Figure 6-1 — Case 6 Configuration



Frame CTs differ from aeroderivative CTs in that the industrial frame CT's performance characteristics generally are more conducive to improved performance in CC applications; that is, industrial frame CTs have a greater amount of exhaust energy to produce steam for the CC's steam turbine portion of the plant. Industrial frame CT sizes, over 400 MW in 60-Hz models, far exceed the maximum aeroderivative size, and on a $/kW basis, industrial frame turbines are less costly.

6.1.2 Electrical & Control Systems

Case 6 includes one 60-Hz CT electric generator with an approximate rating of 240 MVA and output voltage of 13.8 kV. The generator output power is converted to a higher voltage by GSUs for transmission to the external grid, transmitted through an onsite facility switchyard.

The simple-cycle facility is controlled by a control system provided by the CT manufacturer, supplemented by controls for the BOP systems (e.g., water supply to evaporative coolers, fuel supply)

6.1.3 Offsite Requirements

Offsite provisions in Case 6 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile long transmission line.
- **Water Supply for Evaporative Cooler and Miscellaneous Uses:** It is assumed that the water supply source, such as a municipal water system, is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the evaporative cooler is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed at the power plant's site boundary.

6.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $713/kW. Table 6-1 summarizes the cost components for this case. This estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 6-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply), an estimated amount is included for the cost of land.

Table 6-1 — Case 6 Capital Cost Estimate

Case 6 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Combustion Turbine – Simple Cycle F-Class	
Combustion Emissions Controls		Dry Low Emissions Combustor	
Post-Combustion Emissions Controls		None	
Fuel Type		Natural Gas / No. 2 Backup 1 x 237 MW rating	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	233	
Heat Rate, HHV Basis	Btu/kWh	9905	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	20	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	3,100,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		12,300,000
Mechanical – Major Equipment	$	54,000,000	
Mechanical – Balance of Plant	$	17,200,000	
Mechanical Subtotal	$		71,200,000
Electrical Subtotal	$		20,200,000
Project Indirects	$		19,000,000
EPC Total Before Fee	$		122,700,000
EPC Fee	$		12,270,000
EPC Subtotal	$		134,970,000
Owner's Cost Components (Note 2)			
Owner's Services	$		9,448,000
Land	$		600,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		4,500,000
Owner's Cost Subtotal	$		15,748,000
Project Contingency	$		15,072,000
Total Capital Cost	**$**		165,790,000
	$/kW net		**713**

Case 6 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combustion Turbine – Simple Cycle** F-Class
Combustion Emissions Controls	Dry Low Emissions Combustor
Post-Combustion Emissions Controls	None
Fuel Type	Natural Gas / No. 2 Backup 1 x 237 MW rating
Capital Cost Notes	
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

6.3 O&M COST ESTIMATE

Operation and maintenance costs are indicated in Table 6-2. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 6, it is assumed the operating profile results in a starts-driven maintenance overhaul schedule. Refer to Case 5 for an EOH-based overhaul schedule.) In Table 6-2, the cost per start is broken out from the variable O&M costs that cover the consumables.

Table 6-2 — Case 6 O&M Cost Estimate

Case 6 EIA – Non-Fuel O&M Costs – 2019 $s		
Combustion Turbine – Simple Cycle		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**7.00 $/kW-year**
Variable O&M		
Consumables, etc. (Note 2)	$/MWh	**0.60 $/MWh**
CT Major Maintenance (Note 2)	$/Start	**$18,500/Start**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M consumables costs include water, water discharge treatment cost, etc. based on $/MWh. In addition to the Consumables VOM, add CT Major Maintenance VOM costs, which are based on a starts operating regime, with cost per start indicated.		

6.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 6 simple-cycle configuration, NO_X emissions from the CT stack when firing gas are indicated in Table 6-3. Although some locations in the United States would require SCRs and CO catalysts to further reduce stack emissions, an SCR and a CO catalyst have not been included for Case 6.

Table 6-3 — Case 6 Emissions

Case 6 EIA – Emissions Rates		
Combustion Turbine – Simple Cycle		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.030
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 7. COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE

7.1 CASE DESCRIPTION

This case is comprised of one block of a CC power generation unit in a 2x2x1 configuration. The plant includes two industrial frame Model H "advanced technology" CTs and one STG. Case 7 is based on natural gas firing of the CTs, although dual fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

7.1.1 Mechanical Equipment & Systems

Case 7 is comprised of a pair of Model H, dual fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine) with a nominal output for the CC plant of 1114.7-MW gross. Each CT generates 385.2 MW gross; the STG generates 344.3 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1083.3 MW. Refer to Figure 7-1 for a diagram of the Case 7 configuration.

Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output. Each CT is also equipped with burners designed to reduce NO_X emissions. Included in the Case 7 configuration are SCR units for further NO_X emissions reduction and CO catalysts for further CO emissions reduction.

The CTs are Model H industrial frame type CTs with an advanced technology design, since they incorporate the following features:

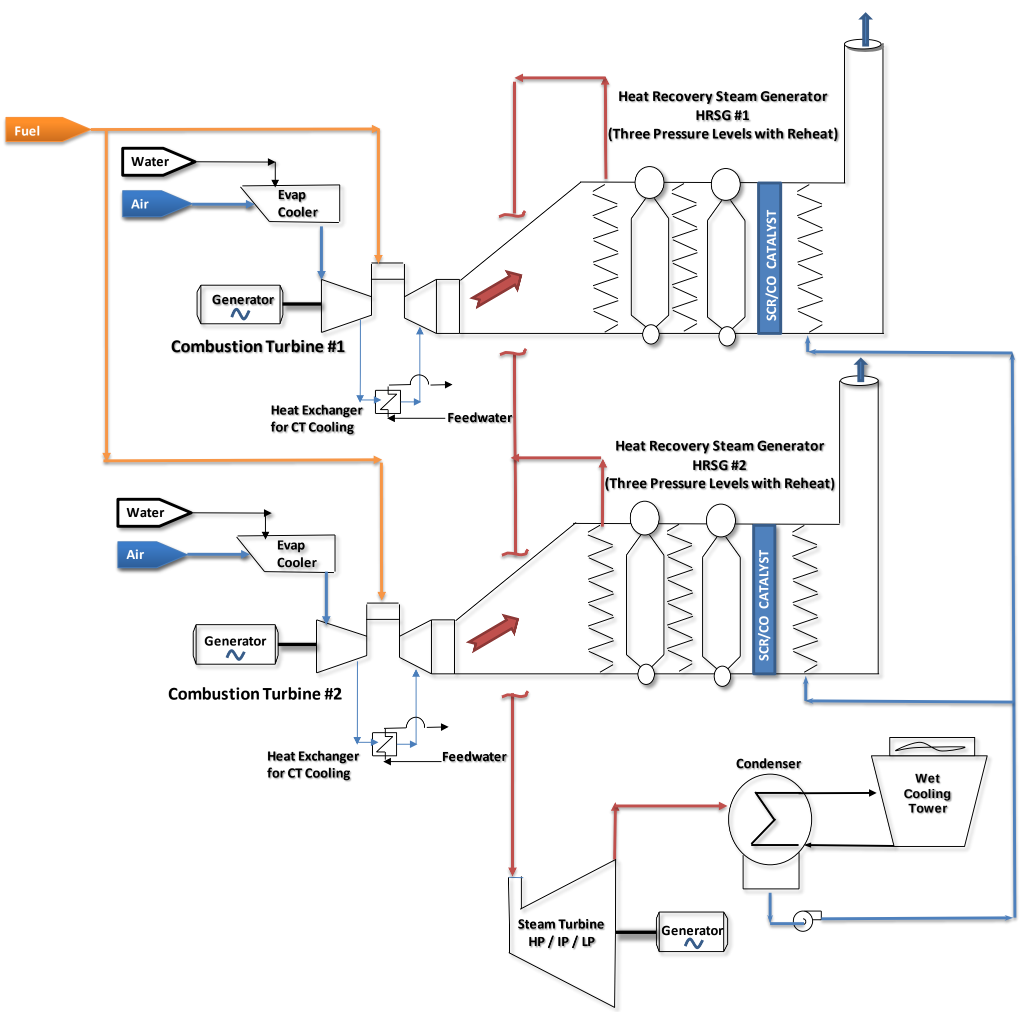
- High firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 7-1, which depicts a dedicated additional cooler for the CT assemblies in Case 7.

The high firing temperature and additional features listed above result in increased MW output and efficiency of the CT as well as in the CC plant.

Hot exhaust gas from each CT is directed to a HRSG, with one HRSG per CT. Steam generated in the HRSGs is directed to the STG. HRSGs may be optionally equipped with additional supplemental firing, however, this feature is not included in Case 7. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

A wet cooling tower system provides plant cooling for Case 7. A wet cooling tower is preferred over the alternative ACC approach since plant performance is better (i.e., greater MW output and higher efficiency) and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce or expensive, such as in desert areas in the southwestern United States.

Figure 7-1 — Case 7 Configuration



7.1.2 Electrical & Control Systems

Case 7 includes one 60-Hz electric generator per CT with an approximate rating of 390 megavolt amperes (MVA) and output voltage of 13.8 kV. The STG includes one 60-Hz electric generator with an approximate 350-MVA rating. The output power from the three generators is converted to a higher voltage by GSUs for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central DCS, which is linked to a CT control system provided by the CT manufacturer. This DCS includes controls for the steam cycle systems and equipment as well as BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

7.1.3 Offsite Requirements

Offsite provisions in Case 7 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

7.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $958/kW. Table 7-1 summarizes the cost components for this case. This estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 7-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 7-1 — Case 7 Capital Cost Estimate

Case 7 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Combined Cycle 2x2x1 H-Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst	
Fuel Type		Natural gas / No. 2 Backup	
Post Firing		No Post Firing	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	1083	
Net Plant Heat Rate, HHV Basis	Btu/kWh	6370	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	60	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	24	
Total Lead Time Before COD	months	42	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		60,000,000
Mechanical – Major Equipment	$	294,000,000	
Mechanical – Balance of Plant	$	196,000,000	
Mechanical Subtotal	$		490,000,000
Electrical Subtotal	$		93,000,000
Project Indirects	$		150,000,000
EPC Total Before Fee	$		793,000,000
EPC Fee	$		79,300,000
EPC Subtotal	$		872,300,000
Owner's Cost Components (Note 2)			
Owner's Services	$		61,061,000
Land	$		1,800,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		71,281,000
Project Contingency	$		94,358,000
Total Capital Cost	**$**		1,037,939,000
	$/kW net		**958**

Case 7 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combined Cycle 2x2x1** H-Class
Combustion Emissions Controls	Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
Capital Cost Notes	
1.Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

7.3 O&M COST ESTIMATE

Table 7-2 indicates O&M costs. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CTs. Additional O&M costs for firm gas transportation service are not included as the facility has dual-fuel capability.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. It also includes the periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CTs and the STG over the long-term maintenance cycle. Planned maintenance costs for the CTs in a given year are based on the number of EOH the CT has run. Typically, a significant overhaul is performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. Case 7 assumes the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a starts-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CTs, typically planned for every six to eight years.

Table 7-2 — Case 7 O&M Cost Estimate

Case 7 EIA – Non-Fuel O&M Costs – 2019 $s		
Combined Cycle 2x2x1		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**12.20 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.87 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, water, and water discharge treatment cost.		

7.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 7 CC configuration, NO_X emissions from the HRSG stacks when firing gas are indicated in Table 7-3. SCRs and CO catalysts are included in the HRSGs to reduce HRSG stack emissions of NO_X and CO below the emission levels in the CT exhaust gas.

Table 7-3 — Case 7 Emissions

Case 7 EIA – Emissions Rates		
Combined Cycle 2x2x1		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075
SO_2	lb/MMBtu	0.001
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 8. COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW

8.1 CASE DESCRIPTION

This case is comprised of one block of a combined-cycle power generation unit. The plant includes one industrial frame Model H "advanced technology" CT, one STG, and one electric generator that is common to the CT and the STG. Case 8 is based on natural gas firing of the CT, although dual fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

8.1.1 Mechanical Equipment & Systems

Case 8 is comprised of one Model H dual fuel CT in a 1x1x1 single-shaft CC configuration with a nominal output for the CC plant of 430.4 MW gross. The CT generates 297.2 MW gross and the STG generates 133.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 418.3 MW. Refer to Figure 8-1 for a diagram of the Case 8 process, which is similar to Case 7.

The Case 8 layout differs from Case 7 in that Case 8 is a single-shaft CC plant. That is, the Case 8 CT, STG, and electric generator all share one horizontal shaft. Therefore, it has a more compact footprint than a plant like Case 7, where the CTs and STG have separate shafts and generators. Refer to Figure 8-2 for a simplified sketch of a single shaft CT/steam turbine/generator unit. Generally, there are no major performance advantages of a single-shaft CC unit. Instead, the advantages are in costs; that is, in the case of a 1x1x1 CC, the single-shaft unit will have only one electric generator whereas a multiple shaft 1x1x1 CC will have two generators. Also, the smaller footprint of the single-shaft unit will lessen BOP costs such as foundations, piping, and cabling costs.

The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X. Included in the Case 8 configuration is an SCR unit for further reduction of NO_X emissions and a CO catalyst for further reduction of CO emissions.

The CT is categorized as Model H industrial frame type CT with an advanced technology design since it incorporates in the design the following features:

- High-firing temperatures (~2900°F)
- Advanced materials of construction

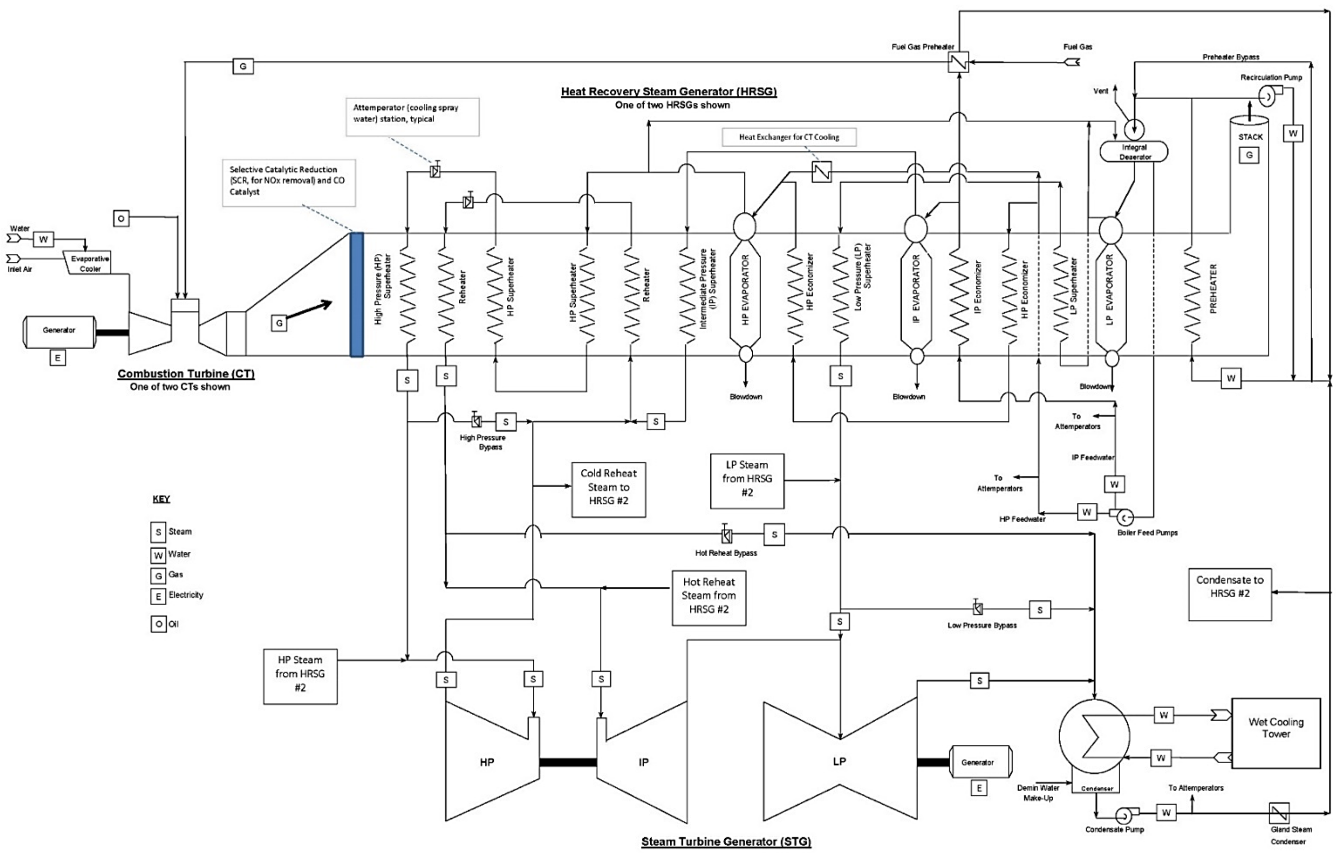
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 8-1, which depicts a dedicated additional cooler for the CT assemblies in Case 8.

The high-firing temperature and additional features listed above result in an increase in MW output and efficiency of the CT as well as in the CC plant.

Hot exhaust gas from the CT is directed to a HRSG. Steam generated in the HRSG is directed to the STG. An HRSG may be optionally equipped with additional supplemental firing, but this feature is not included in Case 8. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

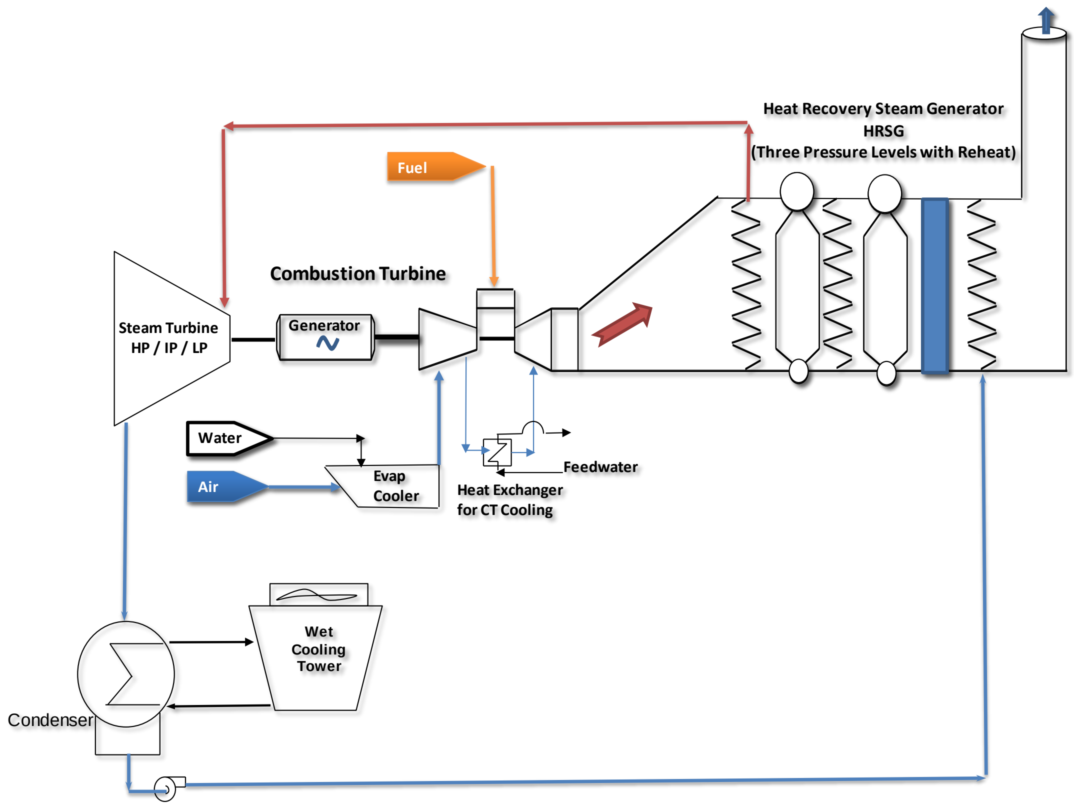
Plant cooling for Case 8 is provided by a wet cooling tower system. Generally, a wet cooling tower is preferred over the alternative ACC approach since plant performance is better (i.e., greater MW output and higher efficiency) with a wet tower and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce or expensive, such as in desert areas in the southwestern United States.

Figure 8-1 — Case 8 Configuration – Process Diagram



Note: Only one CT and one HRSG shown. Second CT and HRSG have the same configurations.

Figure 8-2 — Case 8 Configuration – Simplified Sketch



Conceptual sketch of a 1x1x1 single-shaft CT/steam turbine/generator plant

8.1.2 Electrical & Control Systems

Case 8 includes one 60-Hz electric generator for both the CT and steam turbine, with an approximate rating of 435 MVA and output voltage of 13.8 kV. The output power from the generator is converted to a higher voltage by a GSU for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central DCS, which is linked to a CT control system provided by the CT manufacturer. The DCS system includes controls for the steam cycle systems and equipment as well as the BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

8.1.3 Offsite Requirements

Offsite provisions in Case 8 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.

- **High-Voltage Transmission Line:** A one-mile long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

8.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1084/kW. Table 8-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 8-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 8-1 — Case 8 Capital Cost Estimate

Case 8 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Combined Cycle 1x1x1, Single Shaft** H Class
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	418
Heat Rate, HHV Basis	Btu/kWh	6431
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	7%
Estimated Land Requirement (acres)	$	60
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	1,800,000
Miles	miles	1.00
Substation Expansion	$	0

Case 8 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Combined Cycle 1x1x1, Single Shaft H Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst	
Fuel Type		Natural Gas / No. 2 Backup	
Post Firing		No Post Firing	
	Units		
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	25	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		31,000,000
Mechanical – Major Equipment	$	130,000,000	
Mechanical – Balance of Plant	$	73,000,000	
Mechanical Subtotal	$		203,000,000
Electrical Subtotal	$		28,000,000
Project Indirects	$		80,000,000
EPC Total Before Fee	$		342,000,000
EPC Fee	$		34,200,000
EPC Subtotal	$		376,200,000
Owner's Cost Components (Note 2)			
Owner's Services	$		26,334,000
Land	$		1,800,000
Electrical Interconnection	$		1,800,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		35,834,000
Project Contingency	$		41,203,000
Total Capital Cost	**$**		453,237,000
	$/kW net		**1,084**
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.			
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			

8.3 O&M COST ESTIMATE

Operation and maintenance costs are indicated in Table 8-2. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT.

Variable O&M costs include consumable commodities such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOH the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 8, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a starts-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CT; it is typically planned for every six to eight years.

Table 8-2 — Case 8 O&M Cost Estimate

Case 8 EIA – Non-Fuel O&M Costs – 2019 $s		
Combined Cycle 1x1x1, Single Shaft		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$kW-/year	**14.10 $/kW-year**
Variable O&M (Note 2)	$/MWh	**2.55 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include catalyst replacement, ammonia, water, and water discharge treatment cost.		

8.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 8 CC configuration, NO_X emissions from the HRSG stack when firing gas are indicated in Table 8-3. An SCR and a CO catalyst are included in the HRSG to reduce HRSG stack emissions of NO_X and CO below the emission levels in the CT exhaust gas.

Table 8-3 — Case 8 Emissions

Case 8 EIA – Emissions Rates		
Combined Cycle 1x1x1, Single Shaft		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075 (Note 2)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 9. COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT WITH 90% CO_2 CAPTURE, 430 MW

9.1 CASE DESCRIPTION

This case includes one block of a combined-cycle power generation unit in a 1x1x1 single-shaft configuration. The plant includes one industrial frame Model H "advanced technology" CT, one STG, and one electric generator that is common to the CT and the STG. Case 9 is based on natural gas firing of the CT, although dual fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

In addition, a system is included to remove and capture 90% of the CO_2 in the CT exhaust gas.

Refer to Case 8 for a description the power generation systems, since Case 9 is the same in this regard.

9.1.1 Mechanical Equipment & Systems

This technology case adds a 90% CO_2 capture system to an industrial frame GE Model H 7HA.01 dual fuel CTs in a 1x1x1 single-shaft CC configuration. The nominal output of the CC plant unit without carbon capture is 430.4 MW gross. The major power cycle equipment and configurations are described in Case 8. The CO_2 capture systems are commonly referred to as CCS systems; however, for cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed to be compressed to supercritical conditions and injected into a pipeline that terminates at the facility's fence line. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably. For a brief description of the post-combustion, amine-based CO_2 capture system, please refer to Case 5.

As with the technology of Case 8, the base configuration used for the cost estimate is a single CC unit power generation plant station constructed on a greenfield site of approximately 60 acres. A wet mechanical draft cooling tower is used for plant cycle cooling and the makeup water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water source, reservoir, or river.

For Case 9, to obtain 90% CO_2 removal from the flue gas generated from the CT, he full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustions results in a much lower CO_2 concentration in the flue gas than flue gas from a coal-fired facility. As such, the flue gas absorber and quencher would be much larger in scale on a per ton of CO_2 treated basis than with a coal facility. The stripper and compression system, however, would scale directly with the mass rate of CO_2 captured.

In this scenario, it is not practical to increase the CT size or STG size to account for the steam extraction and added auxiliary power required by the CO_2 capture system. The net power output in the CO_2 capture case is significantly less than Case 8.

The flue gas path differs from the base case (Case 8) in that 100% of the gas is directed to the carbon capture system located downstream of the preheater section of the HRSG. The SCR and CO catalysts would operate the same and the flue gas mass flows would be the same. Rather than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the CO_2 absorber column. The total gross power generated from the CT is approximately the same as Case 8 with no carbon capture.

Steam for the CO_2 stripper is to be extracted from the intermediate-pressure turbine to low-pressure turbine crossover line; however, the steam must be attemporated to meet the requirements of the carbon capture system. The total steam required for the carbon capture system is approximately 306,000 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from 133 MW to 112 MW.

The total auxiliary power required by the plant is 31.7 MW, of which 20 MW is used by the carbon capture system. The net output decreases from the base case (Case 8) from 418 MW to 377 MW. The net plant heat rate for the 90% carbon capture case is 7124 Btu/kWh, HHV basis (compared to 6431 Btu/kWh, HHV basis, for Case 8).

9.1.2 Electrical & Control Systems

The electrical and controls systems for this case is essentially similar is scope to Case 8’s electrical system; however, the auxiliary power system supplies a much larger amount of medium voltage load for the 90% carbon capture case.

The CC facility and the CO_2 capture plant are controlled by a central DCS, which is linked to a CT control system provided by the CT manufacturer. It includes controls for the steam cycle systems and equipment as well as the BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

9.1.3 Offsite Requirements

Offsite provisions in Case 9 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A is a one-mile long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. The volume of water needed for this 90% carbon capture case is significantly higher than for the base CC case (Case 8. The estimated increase in cooling water makeup is approximately 1,500 gallons per minute. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

9.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $2481/kW. Table 9-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 9-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 9-1 — Case 9 Capital Cost Estimate

Case 9 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture** H-Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst	
Fuel Type		Natural gas / No. 2 Backup	
Post Firing		No Post Firing	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	377	
Heat Rate, HHV Basis	Btu/kWh	7124	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	60	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,800,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	30	
Total Lead Time Before COD	months	54	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		31,000,000
Mechanical – Major Equipment	$	130,000,000	
Mechanical – Balance of Plant	$	73,000,000	
Mechanical Subtotal	$		203,000,000
Electrical Subtotal	$		28,000,000
CCS Plant Subtotal	$		362,306,000
Project Indirects	$		90,000,000
EPC Total Before Fee	$		714,306,000
EPC Fee	$		71,430,600
EPC Subtotal	$		785,736,600
Owner's Cost Components (Note 2)			
Owner's Services	$		55,002,000
Land	$		1,800,000
Electrical Interconnection	$		1,800,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		64,502,000
Project Contingency	$		85,024,000
Total Capital Cost	**$**		935,262,600
	$/kW net		**2,481**

Case 9 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture** H-Class
Combustion Emissions Controls	Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
Capital Cost Notes	
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

9.3 O&M COST ESTIMATE

Operation and maintenance costs are indicated in Table 9-2. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT and carbon capture system equipment.

Variable O&M costs include consumable commodities such as water, lubricants, chemicals, solvent makeup, and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOH the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 9, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a start-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CT; it is typically planned for every six to eight years.

For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs.

Table 9-2 — Case 9 O&M Cost Estimate

Case 9 EIA – O&M Costs – 2019 $s		
Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**27.60 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.84 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include catalyst replacement, ammonia, water, and water discharge treatment cost.		

9.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 9 CC configuration with 90% carbon capture, NO_X emissions from the plant when firing gas are indicated in Table 9-3. An SCR and a CO catalyst are included in the HRSG to further reduce plant emissions of NO_X and CO below the emissions levels in the CT exhaust gas. The CO_2 in the CT exhaust gas is reduced by 90% for Case 9.

Table 9-3 — Case 9 Emissions

Case 9 EIA – Emissions Rates		
Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075 (Note 2)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	12
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 10. FUEL CELL, 10 MW

10.1 CASE DESCRIPTION

This case is based on a 10-MW fuel cell power generation facility using a series of identical modular fuel cells. Fuel cells use a potential difference between a cathode and an anode. There is a chemical reaction between oxygen from the air and the fuel within the anode that releases an electron to generate a current. There are many types of fuel cells, but only two technologies have demonstrated capability for utility-sized projects: molten carbonate fuel cell and solid oxide fuel cells. These types of fuel cells operate at high temperatures, (greater than 1,000°F) providing the unique ability to use multiple types of fuel and allows for more design options such as combined heat and power production. This study is based on solid oxide fuel cells oriented in multiple 300-kW stacks. Solid oxide fuel cell stacks are intended to act as modular components that can be combined in various geometries to generate whatever capacity is required for the project. The 10-MW solid oxide fuel cell plant used in this estimate comprises 36 fuel cell stacks operating at 92% capacity. These stacks would be grouped together in 3 groups of 12 stacks, and each group would have its own inverter.

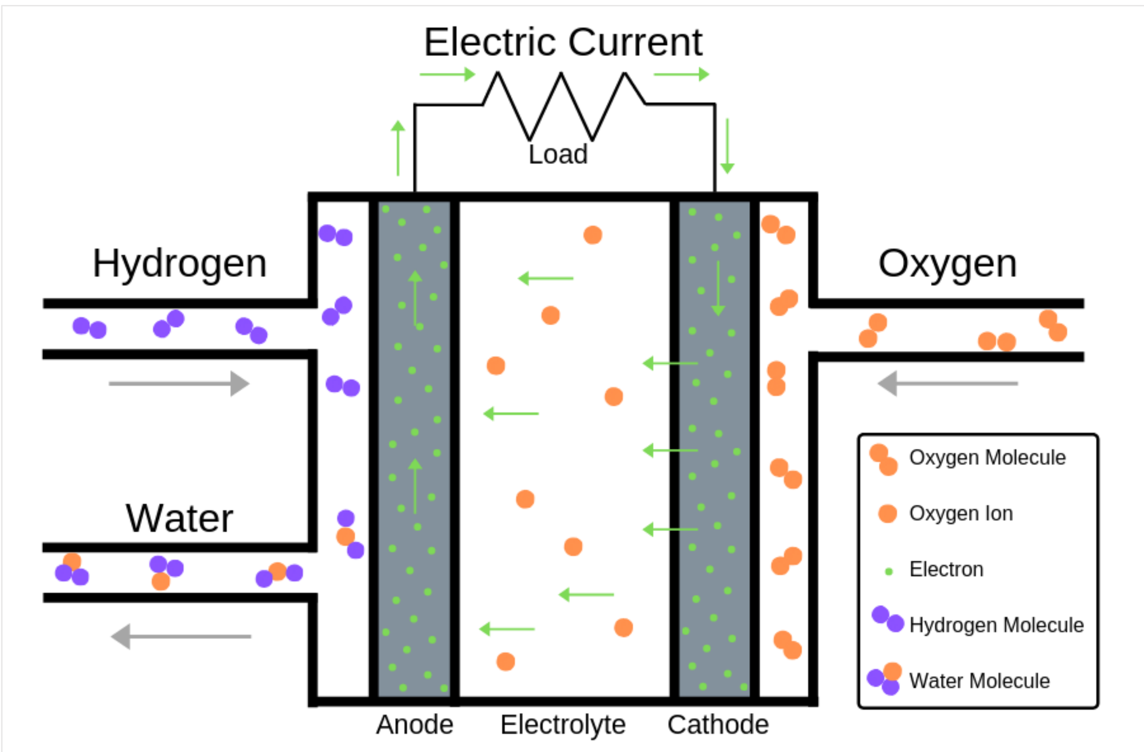
10.1.1 Chemical Operation

A solid oxide fuel cell stack is comprised of thousands of individual fuel cells made of a ceramic electrolyte (typically yttria stabilized zirconia) with a thin anode coating on one side and cathode coating on the other. Solid oxide fuel cells operate by generating steam to reform natural gas methane into hydrogen and carbon monoxide at the anode. At the same time, hot air passes over the cathode which absorbs oxygen molecules. The oxygen molecules react with the electrons in the cathode to form oxygen ions that pass through an electrolyte to combine with the hydrogen and carbon monoxide in the anode to form carbon dioxide, water, a free electron, and heat. The free electron is harnessed and used to generate an electrical current that can be converted into power, the water and heat are recycled to continually generate steam to reform the fuel, and the carbon dioxide is a waste byproduct that is released outside of the fuel cell.

Table 10-1 — Fuel Cell Chemical Reactions

Reaction	Equation
Steam Reforming	$CH_4 + H_2O\ (g) \xrightarrow{yields} 3H_2 + CO$
Electrolyte Reaction	$3H_2 + CO + 2O_2 \xrightarrow{yields} CO_2 + 2H_2O + e^- + Heat$
Net Solid Oxide Fuel Cell	$CH_4 + H_2O\ (g) + 2O_2 \xrightarrow{yields} CO_2 + H_2O + e^- + Heat$

Figure 10-1 — Simplified Solid Oxide Fuel Cell



Adapted from Battery Japan,
https://www.batteryjapan.jp/en-gb/visit/feature10-tokyo.html (accessed June 12, 2019)

10.1.2 Mechanical Equipment & Systems

Due to the small physical size and relative simplicity in design of these modular fuel cell stacks, minimal additional equipment is required. The heating of air and water, fuel reforming, and current generation all occur within the fuel stack itself. Their only external mechanical requirement is a foundation and the gas interconnection for the fuel. For this cost breakdown, however, the stack itself will refer only to the fuel cells within it. The mechanical BOP includes heat recovery components; the fuel processor components; and the supply components for the fuel, water, and air. The electrical equipment includes the power electric equipment such as the inverter and step-up transformer as well as the control and instrumentation equipment. The most expensive single component of the facility is the electric inverters. Fuel cells use a hybrid inverter. Hybrid inverters eliminate the need for a direct current (DC)/DC converter to match the battery voltage and are relatively new on the market. The recent development of these inverters makes them more expensive than other inverters.

Figure 10-2 — Typical Solid Oxide Fuel Cell Project

Source: Office of Fossil Energy – U.S. Department of Energy, ND. Digital Image.
Retrieved from Energy.gov, https://www.energy.gov/fe/science-innovation/clean-coal-research/solid-oxide-fuel-cells (accessed July 8, 2019).

10.1.3 Offsite Requirements

Fuel cells require a water supply and natural fuel supply as well as water discharge. They are typically designed near existing transmission lines and typically have minimal offsite electrical interconnection and transmission costs.

10.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6700/kW. Table 10-2 summarizes the cost components for this case. Although the costs shown are based on an EPC contracting basis, the utility-sized fuel cell projects have been structured as build, own, operate, and maintain by the fuel cell manufacturers with electricity purchase agreements with the client or end user at a set $/kilowatt hour (kWh) basis. With that in mind, most of the solid oxide fuel cell applications are for individual entities, not microgrid or utility operations. These individual entities can range from small-scale businesses to large data centers that need 10+ MW of constant, uninterruptible power because they are unable to be offline for more than a few minutes.

Table 10-2 — Case 10 Capital Cost Estimate

Case 10 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Fuel Cell 34 x 300 kW Gross	
Fuel Cell Type		Solid Oxide	
Fuel Type		Natural Gas	
	Units		
Plant Characteristics			
Net Plant Capacity	MW	10	
Heat Rate	Btu/kWh	6469	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	5%	
Project Contingency	% of Project Costs	4%	
Owner's Services	% of Project Costs	8%	
Estimated Land Requirement (acres)	$	2	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.25	
Metering Station	$	1,200,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	21	
Plant Construction Time	months	3	
Total Lead Time Before COD	months	24	
Operating Life	years	20	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		3,764,000
Mechanical – Fuel Cell Stacks	$	11,601,000	
Mechanical – Balance of Plant	$	16,033,000	
Mechanical Subtotal	$		27,634,000
Electrical Subtotal	$		21,809,000
Project Indirects	$		3,075,000
EPC Total Before Fee	$		56,282,000
EPC Fee	$		2,814,000
EPC Subtotal	$		59,096,000
Owner's Cost Components (Note 2)			
Owner's Services	$		4,728,000
Land	$		60,000
Gas Interconnection	$		1,825,000
Owner's Cost Subtotal	$		6,613,000
Project Contingency	$		2,628,000
Total Capital Cost	**$**		68,337,000
	$/kW net		**6,700**

Case 10 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Fuel Cell** 34 x 300 kW Gross
Fuel Cell Type	Solid Oxide
Fuel Type	Natural Gas
Capital Cost Notes	
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

10.3 O&M COST ESTIMATE

Common practice for solid oxide fuel cell vendors is to build, operate, and maintain the fuel cell plant while charging a fixed monthly O&M to the owner of the project (i.e., the utility or corporation to which they are selling the energy). This leads to a large amount of fixed O&M costs. The only exception being the water supply and discharge, which is left to the owner. These costs are shown as variable O&M within this estimate.

Table 10-3 — Case 10 O&M Cost Estimate

Case 10 EIA – Non-Fuel O&M Costs – 2019 $s		
Fuel Cell		
Fixed O&M – Plant (Note 1)		
Routine Maintenance & Management	$/year	34,000
Fuel Cell Maintenance Reserve	$/year	280,000
Subtotal Fixed O&M	$/year	314,000
$/kW-year	$/kW-year	**30.78 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.59 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance. 2. Variable O&M includes costs of water supply and water discharge.		

10.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Solid oxide fuel cell emissions are dependent on the fuel that is used: biofuel or natural gas. Biofuel allows for a reduction in emissions but carries a higher associated heat rate and operating cost. Therefore, in the interest of being economically competitive, most fuel cells today use natural gas. Even when using natural gas as the fuel source, fuel cells are considered a clean energy source. One important distinction between a natural gas-powered combustion turbine and a fuel cell that uses natural gas is that the fuel cell does not burn the gas. Within the fuel cell, natural gas is reformed with steam, which still releases CO_2 but reduces the other emissions, allowing fuel cells to maintain their "green" status.

Table 10-4 — Case 10 Emissions

Case 10 EIA – Emissions Rates		
Fuel Cell		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0002
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.005
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas		

CASE 11. ADVANCED NUCLEAR, 2156 MW

11.1 CASE DESCRIPTION

The case is based on the AP1000 ("AP" stands for "Advanced Passive"), which is an improvement of AP600. The AP1000 is a pressurized water reactor nuclear plant designed by Westinghouse. The first AP1000 unit came online in June 2018.

11.1.1 Mechanical Equipment & Systems

The AP1000 improves on previous nuclear designs by simplifying the design to decrease the number of components including piping, wiring, and valves. The AP1000 design is also standardized as much as possible to reduce engineering and procurement costs. The AP1000 component reductions from previous designs are approximately:

- 50% fewer valves
- 35% fewer pumps
- 80% less pipe
- 45% less seismic building volume
- 85% less cable

The AP1000 design uses an improved passive nuclear safety system that requires no operator intervention or external power to remove heat for up to 72 hours.

The AP1000 uses a traditional steam cycle similar to other generating facilities such as coal or CC units. The primary difference is that the AP1000 uses enriched uranium as fuel instead of coal or gas as the heat source to generate steam. The enriched uranium is contained inside the pressurized water reactor. The AP1000 uses a two-loop system in which the heat generated by the fuel is released into the surrounding pressurized reactor cooling water. The pressurization allows the cooling water to absorb the released heat without boiling. The cooling water then flows through a steam generator that provide steam to the steam turbine for electrical generation.

11.1.2 Electrical & Control Systems

The advanced nuclear facility has one steam turbine electric generator for each reactor. Each generator is a 60-Hz machine rated at approximately 1,250 MVA with an output voltage of 24 kV. The steam turbine electric generator is connected through a generator circuit breaker to a GSU. The GSI is connected between two circuit breakers in the high-voltage bus in the facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 24 kV to interconnected transmission system high voltage.

The advanced nuclear facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, steam turbine, and associated electric generator and the control of BOP systems and equipment.

11.1.3 Offsite Requirements

Water for all processes at the power plant is obtained from a nearby river or lake. The power plant uses a water treatment system to produce the high-quality process water required as well as service and potable water. The electrical interconnection from the power plant onsite switchyard is typically connected to the transmission line through a nearby substation.

11.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6041/kW. Table 11-1 summarizes the cost components for this case.

Table 11-1 — Case 11 Capital Cost Estimate

Case 11 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Advanced Nuclear (Brownfield)** 2 x AP1000
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	2156
Net Plant Heat Rate, HHV Basis	Btu/kWh	10608
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	20.0%
Estimated Land Requirement (acres)	$	60
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	2,520,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0

Case 11 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Advanced Nuclear (Brownfield)** 2 x AP1000	
	Units		
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	48	
Total Lead Time Before COD	months	72	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		1,675,180,000
Nuclear Island	$	2,463,500,000	
Conventional Island	$	1,379,560,000	
Balance of Plant	$	788,320,000	
Mechanical Subtotal	$		4,631,380,000
Electrical Subtotal	$		788,320,000
Project Indirects	$		1,872,260,000
EPC Total Before Fee	$		8,967,140,000
EPC Fee	$		896,714,000
EPC Subtotal	$		9,863,854,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,972,771,000
Land	$		1,800,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		1,977,091,000
Project Contingency	$		1,184,095,000
Total Capital Cost	**$**		13,025,040,000
	$/kW net		**6,041**
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.			
2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s startup and commissioning costs. Other owner’s costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			

Owner’s costs were reviewed to ensure that utility interconnection costs were accounted for appropriately. Specifically, the transmission line for the nuclear facility is expected to operate at a high voltage to be capable of exporting the large capacity of baseload power.

11.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 11-2 — Case 11 O&M Cost Estimate

Case 11 EIA – Non-Fuel O&M Costs – 2019 $s		
Advanced Nuclear (Brownfield)		
Fixed O&M – Plant ($/year) (Note 1)		
Subtotal Fixed O&M	$/kW-year	**121.64 $/kW-year**
Variable O&M ($/MWh) (Note 2)	$/MWh	**2.37 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.		

11.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Nuclear power plants do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 12. SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW

12.1 CASE DESCRIPTION

This case is based on 12 small reactor modules. Each module has a net capacity of 50 MW for a net plant capacity of 600 MW. The small modular reactor (SMR) case is not based on a particular OEM but rather is a representative SMR plant.

12.1.1 Mechanical Equipment and Systems

The mechanical systems of an SMR are much smaller than those of a traditional nuclear plant. The mechanical systems are similar to that of an advanced nuclear power plant. Each reactor module is comprised of a nuclear core and steam generator within a reactor vessel, which is enclosed within a containment vessel in a vertical orientation. The nuclear core is located at the base of the module with the steam generator located in the upper half of the module. Feedwater enters and steam exits through the top of the vessel towards the steam turbine. The entire containment vessel sits within a water-filled pool that provides cooling and passive protection in a loss of power event. All 12 reactor modules sit within the same water-filled pool housed within a common reactor building.

Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required. To improve on licensing and construction times, each reactor is prefabricated at the OEM's facility and shipped to site for assembly. The compact integral design allows each reactor to be shipped by rail, truck, or barge.

Each module has a dedicated BOP system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for independent operation of each reactor module. The independent operation of each reactor module allows for greater efficiencies at lower operating loads when dispatched capacity is reduced.

Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. An extra reactor bay is including the pool housed with the reactor building. This extra bay allows for removal of individual reactors for maintenance without impacting the remaining reactors.

12.1.2 Electrical and Control Systems

Each SMR has its own generator, which is a 60-Hz machine rated at approximately 45 MVA with an output voltage of 13.8 kV. The steam turbine electric generator is connected through a generator circuit breaker to a GSU that is in turn connected between two circuit breakers in the high-voltage bus in the facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The SMR facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, steam turbine, and associated electric generator and the control of BOP systems and equipment.

12.1.3 Offsite Requirements

Water for all processes at the SMR nuclear power plant is obtained from a nearby river or lake. The SMR power plant uses a water treatment system to produce the high-quality process water required as well as service and potable water. The electrical interconnection from the SMR nuclear power plant onsite switchyard is typically connected to the transmission line through a nearby substation.

12.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6191/kW. Table 12-1 summarizes the cost components for this case.

Table 12-1 — Case 12 Capital Cost Estimate

Case 12 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Small Modular Reactor Nuclear Power Plant** 12 x 50-MW Small Modular Reactor
	Units	
Plant Characteristics		
Net Plant Capacity	MW	600
Net Plant Heat Rate, HHV Basis	Btu/kWh	10046
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	acres	35
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	2,520,000
Miles	miles	1.00
Substation Expansion	$	0

Case 12 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Small Modular Reactor Nuclear Power Plant** 12 x 50-MW Small Modular Reactor	
	Units		
Gas Interconnection Costs			
Pipeline Cost	$/mile	0	
Miles	miles	0.00	
Metering Station	$	0	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	48	
Total Lead Time Before COD	months	72	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		583,524,000
Nuclear Island	$	648,360,000	
Conventional Island	$	421,434,000	
Balance of Plant	$	389,016,000	
Mechanical Subtotal	$		1,458,810,000
Electrical Subtotal	$		259,344,000
Project Indirects	$		551,000,000
EPC Total Before Fee	$		2,852,678,000
EPC Fee	$		285,267,800
EPC Subtotal	$		3,137,945,800
Owner's Cost Components (Note 2)			
Owner's Services	$		235,346,000
Land	$		1,050,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		238,916,000
Project Contingency	$		337,686,000
Total Capital Cost	**$**		3,714,547,800
	$/kW net		**6,191**
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.			
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			

Owner's costs include utility interconnection costs. Specifically, the transmission line for the SMR nuclear power plant is expected to operate at a high voltage to be capable of exporting the full plant output. The SMR costs also take into account that any SMR built at this time would be a first-of-a-kind facility. The indicated costs do not include financial incentives such as tax credits or cost sharing arrangements through public-private partnerships that may support first-of-a-kind facilities.

12.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 12-2 — Case 12 O&M Cost Estimate

Case 12 EIA – Non-Fuel O&M Costs – 2019 $s		
Small Modular Reactor Nuclear Power Plant		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**95.00 $/kW-year**
Variable O&M (Note 2)	$/MWh	**3.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.		

12.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Small modular reactor nuclear power plants do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 13. BIOMASS PLANT, 50 MW

13.1 CASE DESCRIPTION

This case comprises a greenfield biomass-fired power generation facility with a nominal net capacity of 50 MW with a single steam generator and condensing steam turbine with biomass storage and handling systems, BOP systems, in-furnace, and post-combustion emissions control systems. The facility is designed to receive, store, and burn wood chips with moisture content between 20% and 50%. The technology used is a bubbling fluidized bed (BFB) boiler with bed material consisting of sand, crushed limestone, or ash. The facility does not include equipment to further process or dry the fuel prior to combustion. The fuel storage area is assumed to be uncovered. The facility does not have a connection to a natural gas supply and is designed to start up on diesel fuel only. The emission controls are used to limit NO_X and particulate matter, while SO_2 and CO_2 are not controlled.

13.1.1 Mechanical Equipment & Systems

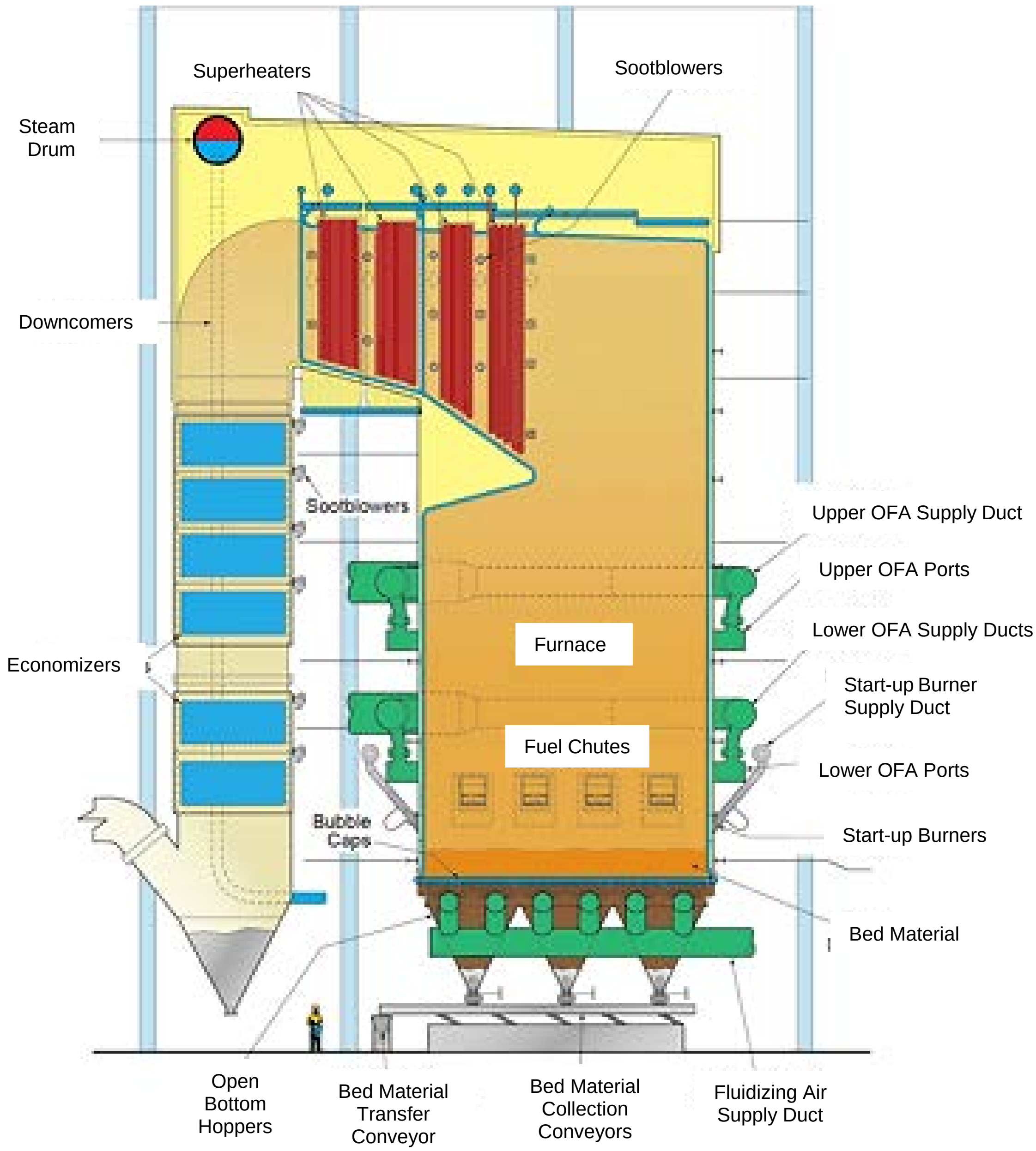
The core technology for this case is a BFB boiler designed to fire wood chips. The boiler is a natural circulation balanced-draft, non-reheat cycle. For this size range, the boiler is assumed to be a top-supported design arranged in a similar manner as shown in Figure 13-1. The BFB furnace consists of horizontally arranged air distribution nozzles in the lower portion of the furnace that introduces air or recirculated flue gas to a bed of sand, ash, or other non-combustible material such as crushed limestone. The balanced-draft boiler consists of water-wall tubes that are refractory lined in the bed area. Air flow is forced upward through the bed material at velocities just beyond the point of fluidization where voids or bubbles start to form within the bed. The bed material is maintained typically at a range of temperatures between 1,400°F to 1,600°F, depending on the moisture content of the fuel. Diesel oil-fired startup burners are used to heat the bed material prior to the introduction of fuel. The biomass fuel is fed through chutes located in the lower furnace. Depending on the moisture content of the fuel, flue gases can be mixed with the fluidized air to control the bed heat release rate to levels that prevent the formation of agglomerated ash. Overfire air is used to complete combustion of the fuel and to control the emissions of NO_X.

The steam cycle includes a condensing steam turbine and turbine auxiliaries, condensate pumps, low-pressure and high-pressure feedwater heaters, boiler feed pumps, economizers, furnace water walls, steam drum, and primary and secondary superheaters. Boiler feed pumps and condensate pumps are provided in a 2x100% sizing basis. The steam conditions at the turbine are assumed to be 1500 psig at 950°F. Cycle cooling is provided by a mechanical draft cooling tower.

The air and flue gas systems include primary and secondary air fans, flue gas recirculation fans, a single tubular air heater, induced draft fans and the associated duct work, and dampers. The fans are assumed to be provided on a 2x50% basis. A material handling is provided to convey the wood chips to the fuel surge bins that direct the fuel to multiple feeders. The BOP equipment includes sootblowers, water treatment system and demineralized water storage tanks, a fire protection and detection system, diesel oil storage and transfer system, compressed air system, aqueous ammonia storage system and feed pumps, an ash handling and storage system, and a continuous emissions monitoring system.

NO_X emissions are controlled in-furnace using OFA and with a high dust SCR system, SO_2 emissions from wood firing are inherently low and therefore are uncontrolled. Particulate matter is controlled using a pulse jet fabric filter baghouse.

Figure 13-1 — Typical BFB Biomass Boiler Arrangement



Babcock & Wilcox Top-Supported BFB Boiler

Source: Babcock & Wilcox, *BFB-boiler-top-supported*, ND. Digital Image. Reprinted with permission from Babcock & Wilcox. Retrieved from Babcock.com, https://www.babcock.com/products/bubbling-fluidized-bed-boilers (accessed June 5, 2019).

The plant performance estimates for BFB boilers firing wood chips is highly dependent on fuel moisture. Generally, BFB boiler efficiencies range from 75% to 80%. The estimated net heat rate firing wood chips is 13,300 Btu/kWh based on the HHV of the fuel.

13.1.2 Electrical & Control Systems

The electrical system for this case includes the turbine generator which is connected via generator circuit breakers to a GSU. The GSU increases the voltage from the generator voltages level to the transmission system high voltage level. The facility and most of the subsystems are controlled using a central DCS. Some systems are controlled using programmable logic controllers, and these systems include the sootblower system, the fuel handling system, and the ash handling system

13.1.3 Offsite Requirements

The facility is constructed on a greenfield site of approximately 50 acres. Wood chips are delivered to the facility by truck and rail. The maximum daily rate for wood chips for the facility is approximately 1500 tons per day.

Water for steam cycle makeup and cooling tower makeup is assumed to be sourced from onsite wells. Wastewater generated from the water treatment systems and the cooling tower blow down is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

13.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $4097/kW. Table 13-1 summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower cost construction labor and has reasonable access to well water and/or water resources, locally sourced wood chips, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed. No special systems are needed to prevent freezing or to account for snow loads on structures.

Table 13-1 — Case 13 Capital Cost Estimate

Case 13 EIA – Capital Cost Estimates – 2019 $s			
Configuration		50-MW Biomass Plant Bubbling Fluidized Bed	
Combustion Emissions Controls		OFA	
Post-Combustion Emissions Controls		SCR / Baghouse	
Fuel Type		Woodchips	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	50	
Heat Rate, HHV Basis	Btu/kWh	13300	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	50	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	N/A	
Miles	miles	N/A	
Metering Station	$	N/A	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		22,266,000
Mechanical – Boiler Plant	$	60,477,000	
Mechanical – Turbine Plant	$	8,230,000	
Mechanical – Balance of Plant	$	20,111,000	
Mechanical Subtotal	$		88,818,000
Electrical – Main and Auxiliary Power Systems	$	3,543,000	
Electrical – BOP and I&C	$	17,657,000	
Electrical – Substation and Switchyard	$	5,408,000	
Electrical Subtotal	$		26,608,000
Project Indirects	$		15,418,000
EPC Total Before Fee	$		153,110,000
EPC Fee	$		15,311,000
EPC Subtotal	$		168,421,000
Owner's Cost Components (Note 2)			
Owner's Services	$		11,789,000
Land	$		1,500,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		14,489,000
Project Contingency	$		21,949,000
Total Capital Cost	$		204,859,000
	$/kW net		**4,097**

Case 13 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**50-MW Biomass Plant** Bubbling Fluidized Bed
Combustion Emissions Controls	OFA
Post-Combustion Emissions Controls	SCR / Baghouse
Fuel Type	Woodchips
Capital Cost Notes	
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

13.3 O&M COST ESTIMATE

The O&M costs for 50-MW biomass wood-fired generation facility are summarized in Table 13-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and G&A. Major overhauls for the facility are generally based on a three-year basis for boiler equipment and firing equipment and a six-year basis for the steam turbine. Shorter outages (e.g., change out SCR catalyst) are generally performed on a two-year cycle.

Non-fuel variable costs for this case include SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, and bed material makeup.

Table 13-2 — Case 13 O&M Cost Estimate

Case 13 EIA – Non-Fuel O&M Costs – 2019 $s		
50-MW Biomass Plant		
Fixed O&M – Plant (Note 1)		
Labor	$/year	3,510,000
Materials and Contract Services	$/year	1,250,000
Administrative and General	$/year	1,526,000
Subtotal Fixed O&M	$/year	6,286,000
$/kW-year	$/kW-year	**125.72 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.83 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, water, ash disposal, and water discharge treatment cost.		

13.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 13-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.08 lb/MMBtu. The SO_2 emissions from wood fired combustion are assumed to be negligible and are uncontrolled. The CO_2 emissions estimates are based on emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 13-3 — Case 13 Emissions

Case 13 EIA – Emissions Rates		
50-MW Biomass Plant		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.08 (Note 2)
SO_2	lb/MMBtu	<0.03 (Note 3)
PM	lb/MMBtu	0.03 (Note 4)
CO_2	lb/MMBtu	206 (Note 5)
Emissions Control Notes		
1. Wood Fuel – 20% to 50% Fuel Moisture		
2. NOx Removal using OFA, and SCR		
3. SO2 is assumed negligible in for wood fuel		
4. Controlled using pulse jet fabric filter		
5. Per 40 CFR 98, Subpt. C, Table C-1		

CASE 14. 10% BIOMASS CO-FIRE RETROFIT

14.1 CASE DESCRIPTION

This case is a retrofit of an existing 300-MW pulverized coal power facility to cofire wood biomass at a rate corresponding to 10% of the equivalent output in MW. In this scenario, the biomass fuel displaces coal to generate approximately 30 MW of the net output with the balance from coal. The type of boiler assumed for the retrofit is a balanced draft, radiant reheat type boiler that fires a high to medium sulfur bituminous coal through pulverizers. The firing system is either tangential or wall-fired and is assumed to have low-NO_X features such as LNBs and OFA. The biomass is a pelletized wood-based material formed from sawdust or paper. The biomass is not mixed with the coal and is not fed through the pulverizers but is introduced into the boiler through separate burners in new water-wall openings. The heat input from the biomass displaces the equivalent heat input from coal.

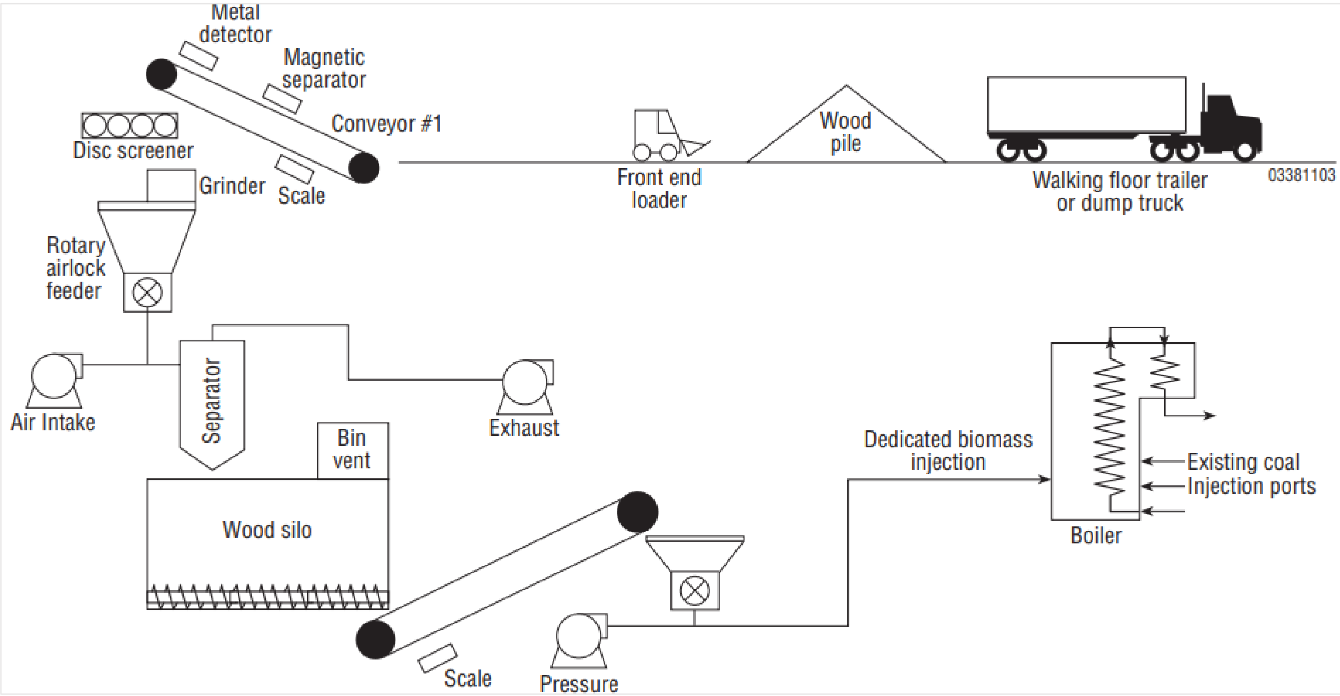
14.1.1 Mechanical Equipment & Systems

Figure 14-1 summarizes schematically the equipment required for the retrofit of biomass cofiring equipment to an existing 300-MW coal-fired facility. A portion of the facility is modified to receive and store the biomass fuel. The biomass fuel storage area is constructed on a concrete pad and a roof to minimize exposure to rain and snow. A reclaim system will convey the fuel to a grinder and feeder system located near the boiler. The biomass is then fed into surge bins feeding four individual burners. The biomass is conveyed to the boiler with heated primary air. The biomass burners have windboxes for secondary air distribution. The boiler water walls are modified to account for the new biomass firing equipment.

The BOP equipment modifications include additional fire detection and protection equipment. Additional duct control equipment is provided to minimize dangerous accumulation of fines. Additional automated and manual wash water systems are provided to remove any dust accumulation along the material handling path. Additional sootblowers are included in areas of the upper furnace and convective passes to address increases in fouling and slagging by the cofiring of the wood biomass. No modifications to the boiler post-combustion emissions controls are necessary; however, the boiler controls are modified to account for the redistribution of combustion air.

The introduction of biomass into the boiler will decrease the boiler efficacy. The estimated increase in heat rate for the 100% coal-fired base case is approximately 1.5%.

Figure 14-1 — Biomass Cofiring in Coal-Fired Boilers, Separate Feed Arrangement



Source: NREL, *DOE/EE-0288 Biomass Cofiring in Coal-Fired Boilers*, 2004. PDF.
Retrieved from NREL.gov, https://www.nrel.gov/docs/fy04osti/33811.pdf (accessed June 13, 2019).

14.1.2 Electrical & Control Systems

No major modifications to the electrical system are needed for this retrofit; however, new power feeds to the biomass fuel handling equipment and biomass conveying fans will be required. The plant DCS system will be upgraded to accommodate the additional input/output and control systems for the biomass handling and combustions systems.

14.1.3 Offsite Requirements

The pelletized wood biomass is delivered to the facility by truck. The maximum daily biomass fuel rate for the facility is approximately 500 tons per day, which corresponds to 20 to 24 trucks per day. New roads and additional site access are provided to accommodate the increase in daily truck traffic.

There are no substantial increases in the demands of cycle makeup water or cooling tower makeup. The service water demands increase due to the additional washdown systems needed for dust control, but the current water resources are sufficient to meet these demands.

14.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $705/kW based on the net output from the biomass; in this case, it is 30 MW. Table 14-1 summarizes the cost components for this case. The basis of the estimate assumes that the site has sufficient space for the biomass fuel storage and sufficient auxiliary power capacity for the new electrical loads.

Table 14-1 — Case 14 Capital Cost Estimate

Case 14 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**10% Biomass Co-Fire Retrofit** 300-MW PC Boiler
Combustion Emissions Controls		LNB / OFA / SCR
Post-Combustion Emissions Controls		ESP
Fuel Type		Wood Pellets, up to 10%
	Units	
Plant Characteristics		
Equivalent Biomass Plant Capacity	MW	30
Heat Rate, HHV Basis	% Change from Baseline	+ 1.5%
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	20%
Owner's Services	% of Project Costs	7%
Estimated Land Requirement (acres)	$	0
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	1,200,000
Miles	miles	1.00
Substation Expansion	$	N/A
Gas Interconnection Costs		
Pipeline Cost	$/mile	N/A
Miles	miles	N/A
Metering Station	$	N/A
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	8
Total Lead Time Before COD	months	26
Operating Life	years	20
Cost Components (Note 1)		**Total**
Civil/Structural/Architectural Subtotal	$	1,572,000
Mechanical Subtotal	$	9,880,000
Electrical Subtotal	$	2,769,000
Project Indirects	$	749,000
EPC Total Before Fee	$	14,970,000
EPC Fee	$	1,497,000
EPC Subtotal	$	16,467,000

Case 14 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**10% Biomass Co-Fire Retrofit** 300-MW PC Boiler
Combustion Emissions Controls		LNB / OFA / SCR
Post-Combustion Emissions Controls		ESP
Fuel Type		Wood Pellets, up to 10%
	Units	
Owner's Cost Components (Note 2)		
Owner's Services	$	1,153,000
Land	$	0
Electrical Interconnection	$	0
Gas Interconnection	$	0
Owner's Cost Subtotal	$	1,153,000
Project Contingency	$	3,524,000
Total Capital Cost	**$**	21,144,000
	$/kW net	**705**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

14.3 O&M COST ESTIMATE

The O&M costs for biomass cofiring are summarized in Table 14-2. Costs are normalized by the equivalent electrical output from biomass. The fixed costs cover the O&M labor, contracted maintenance services and materials, and G&A for the cofiring systems only.

Non-fuel variable costs for this technology case include increased water treatment costs and increased fly ash and bottom ash disposal costs.

Table 14-2 — Case 14 O&M Cost Estimate

Case 14 EIA – Non-Fuel O&M Costs – 2019 $s		
10% Biomass Co-Fire Retrofit		
Fixed O&M – Plant (Note 1)		
Labor	$/year	267,000
Materials and Contract Services	$/year	350,000
Administrative and General	$/year	150,000
Subtotal Fixed O&M	$/year	767,000
$/kW-year	$/kW-year	**25.57 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.90 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, ash disposal, and water discharge treatment cost.		

14.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 14-3. No major modifications to the emissions controls system are required; however, the combustion air and OFA distribution within the furnace need to be tuned and adjusted to optimize the performance on the biomass fuel. The NO_X emissions as measured at the outlet of the economizer are expected to decrease by up to 20% from baseline levels depending on the type of boiler and the coal fired. The SO_2 emissions are expected to decrease by approximately 8%. and the CO_2 emissions derived from coal reduce by approximately 8% from baseline levels.

Table 14-3 — Case 14 Emissions

Case 14 EIA – Emissions Offsets		
10% Biomass Co-Fire Retrofit		
Predicted Emissions Rates (Note 1)		
NOx	% change at Economizer Outlet	- 0 to -20% (Note 2)
SO_2	% change at Economizer Outlet	-8%
PM	% change at Economizer Outlet	0%
CO_2 (Derived from Coal)	% change at Economizer Outlet	-8% (Note 3)
Emissions Control Notes		
1. Emissions are presented as differentials to the baseline, uncontrolled emissions rates		
2. In-furnace NOx reduction systems in place; LNBs and OFA		
3. Based on a reduction of the coal derived CO2		

CASE 15. GEOTHERMAL PLANT, 50 MW

15.1 CASE DESCRIPTION

This case is a hydrothermal-based net 50-MW geothermal power plant using a binary cycle. Capital costs for geothermal power are highly site specific and technology specific. There are two distinct types of geothermal systems: Enhanced Geothermal System (EGS) and Hydrothermal. EGS technology uses fractures, or porous characteristics, in dry, hot rock to create a geothermal reservoir by injecting the water into the hot rock before commercial operation. Hydrothermal systems use naturally occurring geothermal aquifers that already have hot liquid water and/or steam within fractured or porous reservoirs.

Either type of geothermal system can use one of three general technologies for the generation of electricity: dry, flash, and binary cycle. The choice of technology is usually based on the temperature of the water (liquid, steam, or both) found within the geothermal reservoir (or the temperature of the EGS-developed reservoir). In some cases, these technologies may be combined, such as a flash plant with a bottoming binary cycle. Dry steam technology is used with geothermal reservoirs that produce superheated, dry steam that self-discharges from the production well. These systems are typically reserved for the upper range of reservoir temperatures. Flash technology is used with geothermal reservoirs that produce steam and water. The steam and water are separated at the surface with the steam being routed to a steam generator and the liquid either being reinjected into the well or being flashed into steam by a pressure reduction before being routed to a steam generator. This case assumes the use of the third technology: binary cycle.

The use of a binary cycle rather than flash would typically be considered for geothermal production temperatures of 350°F or less, although there is no firm temperature demarcation point as to when binary versus flash technologies should be used. Reservoirs with lower temperatures (approximately 350°F or less) will typically be produced via wells that will not self-discharge and require a means of pumping the fluid from the reservoir up to the surface. This pumping is usually accomplished using individual pumps installed into each production well. The binary cycle is also commonly referred to as Organic Rankine Cycle.

When using a binary cycle, the produced reservoir fluid is maintained as a pressurized liquid (i.e., at a pressure above the saturation pressure corresponding to the fluid's temperature) within the production well, the surface piping and plant equipment, all the way to the injection wells where it is readmitted to the reservoir. This pressurized state keeps the hot geothermal fluid from boiling (flashing), and the geothermal fluid is never in contact with ambient air. A portion of the heat content of the pressurized geothermal fluid is transferred into a working fluid via one or more heat exchanger(s). The working fluid is typically vaporized within the heat exchanger(s) and is then sent to a turboexpander where it expands and produces mechanical power. The turboexpander drives an electrical generator. Binary cycle power plants may use either air-cooling or water-cooling for condensing the turbo-expander exhaust back into a liquid. Currently, most geothermal plants operating within the United States use flash steam technology; however, this case assumes the use of binary cycle technology due to the lower temperatures of remaining unused geothermal resources.

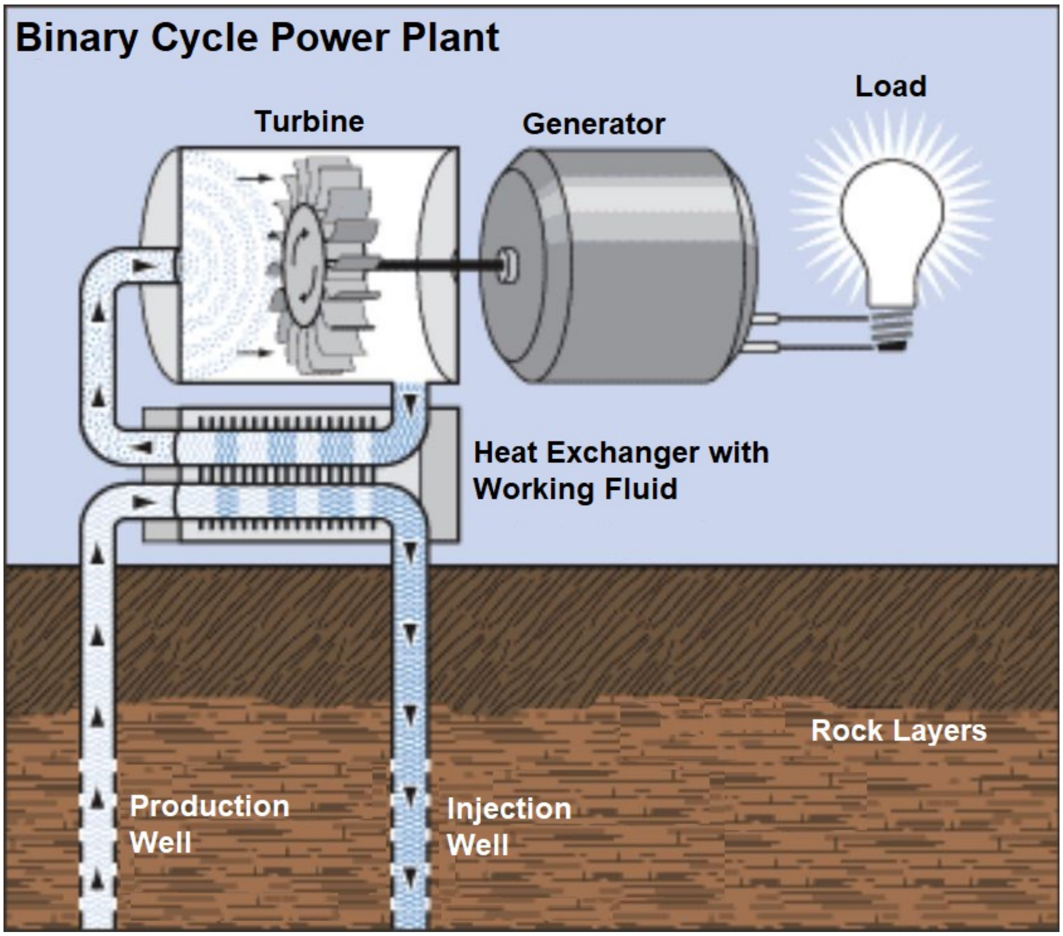
Utility-scale geothermal power requires high-temperature aquifers to be cost effective. Locating aquifers with a sufficiently high temperature and sustainable flow rate is a significant task. The costs associated with exploration and drilling of the wells often accounts for over 50% of the total overnight capital expenditures for a geothermal project. To isolate the costs of building and maintaining the geothermal plant itself, this study has assumed that the geothermal plant was built on a brownfield site. This means that a sufficiently hot aquifer has already been identified with production and injection wells already developed. While this is rare, it does occasionally occur within the industry. As the geothermal well gets hotter, lower flow rates are required to maintain the same output thus reducing capital costs and operation costs. This analysis assumes that the geothermal reservoir has a temperature of 300°F.

15.1.1 Mechanical Equipment & Systems

A binary cycle power plant has three independent fluid loops: (1) the geothermal fluid loop, (2) the closed working fluid loop, and (3) the open cooling water loop. A simplified image of binary cycle including loops (1) and (2) can be seen in Figure 15-1. The open geothermal loop is comprised of the production well(s), downhole well pump(s), piping to the power plant, heat exchanger(s) coupled with the working fluid, piping to the injection well field, and the injection well(s). The temperature and flow rate of the geothermal loop is dependent upon the properties of the reservoir, but it is always kept at a pressure above its flash point. A single geothermal production well typically has the potential to convert the well's thermal power into around 3 MW of electric power. A geothermal plant typically has between a 2:1 ratio and a 1:1 ratio of production wells to injection wells. This system is assumed to have 17 production wells and 10 injections wells.

The closed working fluid loop is comprised of a pump for pumping the working fluid in the liquid phase, a turboexpander that is connected to a generator, and heat exchanger(s). Heat exchangers transfer heat from the hot geothermal fluid to the working fluid, essentially boiling the working fluid and the resulting vapor is sent through the turboexpander. After the turboexpander, another heat exchanger (condenser) transfers heat from the working vapor, condensing it back into a liquid to be pumped back through the cycle. The working fluid typically has a low boiling point, which allows for reliable operation, and has a high conversion efficiency for good utilization of the geothermal heat. The 50-MW geothermal plant uses two working fluid loops, each with its own 25-MW steam turbine and generator.

Figure 15-1 — Geothermal Binary Cycle Power Plant



Source: Office of Energy Efficiency & Renewable Energy,
Geothermal Technologies Office – U.S. Department of Energy, *binaryplant*, ND. Digital Image
Retrieved from Energy.gov, https://www.energy.gov/eere/geothermal/electricity-generation (accessed July 9, 2019)

The final loop, which is not shown in the diagram above, is an open loop of cooling water which is comprised of a cooling water pump, heat exchanger (condenser), and the cooling tower. The cooling system used for this case is a wet cooling tower. Water vapor from the cooling tower is the only emission of binary cycle power plants, with the exception of a cooling water blowdown stream from the cooling tower. Air-cooled condensers can also be used, but risk declines in power output during periods of high ambient temperature.

15.1.2 Electrical & Control Systems

This 50-MW geothermal plant uses two 25-MW turboexpanders with independent generators. Each generator has its own step-up transformer and circuit breaker. After the circuit breaker, each electrical connection is combined via a high-voltage bus into a high-voltage circuit breaker before being fed into the grid.

15.1.3 Offsite Requirements

Geothermal plants use renewable heat from within the earth and naturally occurring water sources. This allows geothermal facilities to be free from requiring offsite fuel or materials. Water for the cooling system is either sourced from offsite or uses nearby natural sources such as a lake, freshwater well, or river. Unlike dry steam and flash power plants, binary cycle plants continually reinject all of the produced geothermal fluid back into the reservoir, thereby removing the need for brine processing and disposal. This reinjection of all produced mass also helps in maintaining reservoir pressure since there is no net mass removal from the reservoir.

15.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $2521/kW. Table 15-1 summarizes the cost components for this case. This price is dependent on the technology used, reservoir temperature, and location of the power plant. This analysis assumes that due to geological constraints, only the west coast of the United States should be considered for this cost estimate (i.e., California, Oregon, Washington, Nevada, and Idaho).

Table 15-1 — Case 15 Capital Cost Estimate

Case 15 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Geothermal 50 MW	
Plant Configuration		Binary Cycle	
	Units		
Plant Characteristics			
Net Plant Capacity	MW	50	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	15%	
Project Contingency	% of Project Costs	8%	
Owner's Services	% of Project Costs	12%	
Estimated Land Requirement (acres)	$	200	
Estimated Land Cost ($/acre)	$	10,000	
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		8,463,000
Mechanical – Steam Turbine	$	18,750,000	
Mechanical – Production / Injection System	$	21,644,000	
Mechanical – Balance of Plant	$	19,663,000	
Mechanical Subtotal	$		60,057,000
Electrical – BOP and I&C	$	5,475,000	
Electrical – Substation and Switchyard	$	4,302,000	
Electrical Subtotal	$		9,777,000
Project Indirects	$		9,838,000
EPC Total Before Fee	$		88,135,000
EPC Fee	$		13,220,000
EPC Subtotal	$		101,355,000
Owner's Cost Components (Note 2)			
Owner's Services	$		12,163,000
Land	$		2,000,000
Electrical Interconnection	$		1,200,000
Owner's Cost Subtotal	$		15,363,000
Project Contingency	$		9,337,000
Total Capital Cost	**$**		126,055,000
	$/kW net		**2,521**
Capital Cost Notes			

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.

2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s startup and commissioning costs. Other owner’s costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.

15.3 O&M COST ESTIMATE

Different geothermal technologies have different O&M costs. Binary cycle geothermal plants are able to maintain the turbine (turboexpander) at a lower cost than other geothermal technologies due to the increased quality of the working fluid compared to the geothermal steam that passes through the turbine in dry steam and flash plant designs. What binary cycle plants save in turbine maintenance is lost in the additional pump maintenance since the other technologies do not require downhole pumps. Additionally, for binary cycle plants to produce equivalent net power outputs, they require higher flow rates from the production wells and have more overall pumps and piping compared to the other geothermal technologies.

Table 15-2 — Case 15 O&M Cost Estimate

Case 15 EIA – Non-Fuel O&M Costs – 2019 $s		
Geothermal		
Fixed O&M – Plant (Note 1)		
Labor	$/year	1,470,000
Steam Turbine Maintenance	$/year	3,750,000
Materials and Contract Services	$/year	661,800
Administrative and General	$/year	545,400
Subtotal Fixed O&M	$/year	6,427,200
$/kW-year	$kW-year	**128.54 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.16 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

15.4 ENVIRONMENTAL & EMISSIONS INFORMATION

While flash and dry geothermal power plants produce small emissions, binary cycle geothermal plants produce no regulated environmental emissions. The only emission is water vapor and small amounts of blowdown tower water from the cooling tower because the working fluid is kept in a closed loop and the geothermal loop is only open to the underground reservoir. Therefore, the emissions of NOx, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 16. INTERNAL COMBUSTION ENGINES, LANDFILL GAS, 30 MW

16.1 CASE DESCRIPTION

This case is a landfill gas-fired power plant that is powered by four reciprocating internal combustion engines. Each engine is nominally rated at 9.1 MW for a net capacity of 35.6 MW. The case only includes the power block and does not include any of the landfill gas gathering or filtering systems.

16.1.1 Mechanical Equipment and Systems

The RICE power plant comprises four large-scale gas-fired engines that are coupled to a generator. The power plant also includes the necessary engine auxiliary systems, which are fuel gas, lubricated oil, compressed air, cooling water, air intake, and exhaust gas.

Each engine is comprised of 10 cylinders in a V configuration. The engines are a four-stroke, spark-ignited engine that operates on the Otto cycle. Each engine includes a turbocharger with an intercooler that uses the expansion of hot exhaust gases to drive a compressor that raises the pressure and density of the inlet air to each cylinder. The turbocharger is an axial turbine/compressor with the turbine and the centrifugal compressor mounted on the same shaft. Heat generated by compressing the inlet air is removed by a water-cooled “intercooler.” Turbocharging increases the engine output due to the denser air/fuel mixture.

The engines are cooled using a water/glycol mixture that circulates through the engine block, cylinder heads, and the charge air coolers. The cooling system is a closed-loop system and is divided into a high-temperature and a low-temperature circuit. The high-temperature circuit cools the engine block, cylinder heads, and the first stage of the charge air cooler. The low-temperature cooler cools the second stage of the charge air cooler. Heat is rejected from the cooling water system by air-cooled radiators.

16.1.2 Electrical and Control Systems

The electrical generator is coupled to the engine. The generator is a medium voltage, air-cooled, synchronous AC generator.

The engine OEM provides a DCS that allows for a control interface, plant operating data, and historian functionality. The control system is in an onsite building. Programmable logic controllers are also provided throughout the plant for local operation.

16.1.3 Offsite Requirements

Fuel for combustion is delivered through the landfill gas gathering system. As water consumption is minimal at the power plant, water is obtained from the municipal water supply. The power plant also includes minimal water treatment for onsite water usage. Wastewater is treated using an oil-water separator and then is directed to a municipal wastewater system. Used oil that is no longer filterable is stored in a waste oil tank and removed offsite with a vacuum truck.

The power plant's onsite switchyard is connected to the transmission system through a nearby substation.

16.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1563/kW. Table 19-1 summarizes the cost components for this case.

Table 16-1 — Case 16 Capital Cost Estimate

Case 16 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Internal Combustion Engines** 4 x 9.1 MW
Fuel Type		Landfill Gas
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	35.6
Net Plant Heat Rate, HHV Basis	Btu/kWh	8513
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	8%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	$	10
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	720,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0
Typical Project Timelines		

Case 16 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Internal Combustion Engines 4 x 9.1 MW	
Fuel Type		Landfill Gas	
	Units		
Development, Permitting, Engineering	months	12	
Plant Construction Time	months	18	
Total Lead Time Before COD	months	30	
Operating Life	years	30	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		12,464,000
Engines (Note 3)	$	13,637,000	
Mechanical BOP	$	8,735,000	
Mechanical Subtotal	$		22,372,000
Electrical Subtotal	$		9,803,000
Project Indirects	$		180,000
EPC Total Before Fee	$		31,182,000
EPC Fee	$		3,118,000
EPC Subtotal	$		34,300,000
Owner's Cost Components (Note 2)			
Owner's Services	$		2,573,000
Land	$		300,000
Owner Furnished Equipment (Note 3)	$		13,637,000
Electrical Interconnection	$		720,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		17,230,000
Project Contingency	$		4,122,000
Total Capital Cost	**$**		55,652,000
	$/kW net		**1,563**
Capital Cost Notes			
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.			
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.			
3. Engines and associated auxiliary procured from the engine OEM.			

Owner's costs were reviewed to ensure that utility interconnection costs were accounted for appropriately. Specific to the landfill gas case, a natural gas interconnection for engine fuel is not required. Additionally, it is expected that some electrical and water utilities will already be available at the existing landfill site.

16.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 16-2 — Case 16 O&M Cost Estimate

Case 16 EIA – Non-Fuel O&M Costs – 2019 $s		
Internal Combustion Engines		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**20.10 $/kW-year**
Variable O&M (Note 2)	$/MWh	**6.20 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables.		

16.4 ENVIRONMENTAL & EMISSIONS INFORMATION

NOx and CO emissions are maintained through an SCR and CO catalyst installed in the exhaust system of each engine. SO_2 is uncontrolled but minimal and below emission limits because of the low amounts of SO_2 in the natural gas fuel. Water, wastewater, solid waste, and spent lubricating oil are disposed of through conventional means.

Table 16-3 — Case 16 Emissions

Case 16 EIA – Emissions Rates		
Internal Combustion Engines		
Predicted Emissions Rates – Natural Gas		
NOx	lb/MMBtu	0.02 (Note 1)
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.03
CO_2	lb/MMBtu	115 (Note 2)
Emissions Control Notes		
1. With SCR		
2. Per 40 CFR98 Sub Part C – Table C1		

CASE 17. HYDROELECTRIC PLANT, 100 MW

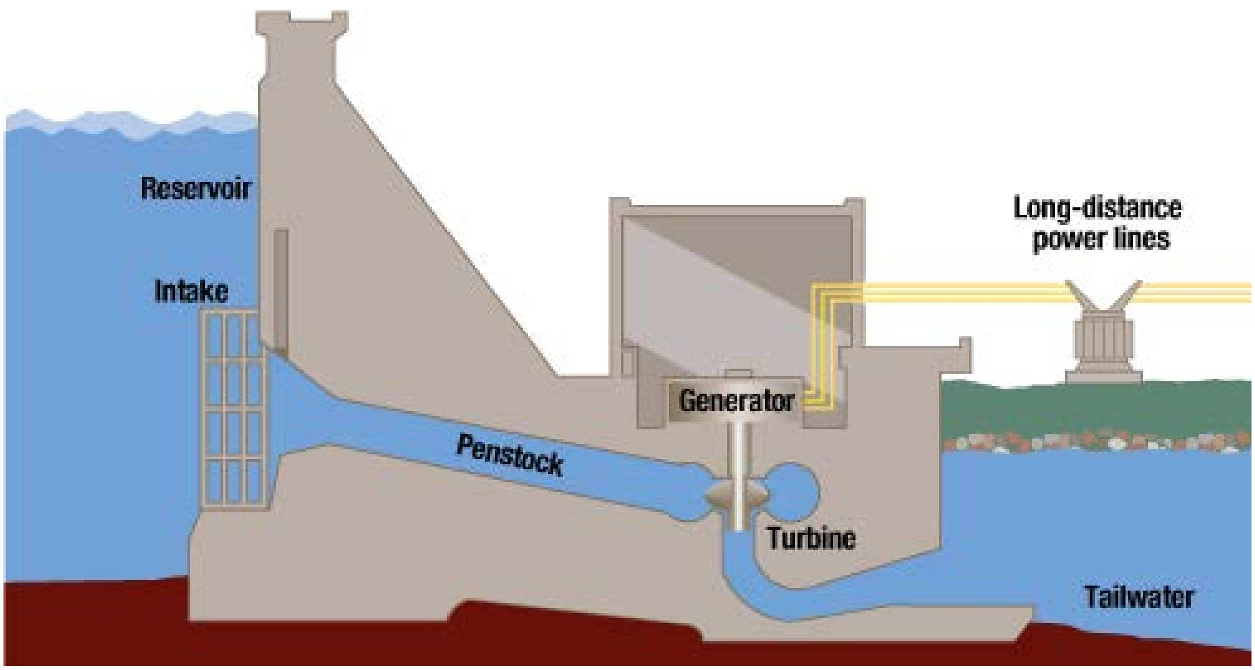
17.1 CASE DESCRIPTION

This case is based on a “New Stream Reach Development” 100-MW hydroelectric power plant with 75 feet of available head. Types of hydroelectric power plants including “run-of-river,” “storage,” and “pumped storage.” This case is based on a “storage” type hydropower plant that includes a dam to store water in a reservoir where water is released through tunnels to a powerhouse to spin a turbine.

Figure 17-1 shows a diagram of the major components of a storage-type hydroelectric power plant. The dam structure holds water in a reservoir. Water passes through an intake in the reservoir through the penstock. The penstock consists of concrete ‘power tunnels’ that direct water to a turbine that spins a generator that distributes electric power to the grid.

Case 17 is based on a concrete dam with a spillway and diversion tunnel to control the water level in the reservoir. There are two identical penstocks approximately 4.5 meters in diameter. Each penstock leads to a Francis-type hydro-turbine. Each of the two turbine-generators is rated for 50 MW. Power is stepped up from 13.8 kV to 154 kV for distribution.

Figure 17-1 — Storage-Type Hydroelectric Power Plant



Source: Tennessee Valley Authority, How Hydroelectric Power Works, ND. Digital Image. Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/How-Hydroelectric-Power-Works (accessed June 13, 2019).

Figure 17-2 shows the dam and spill way of a storage-type hydroelectric power plant.

Figure 17-2 — Dam and Spillway of Hydroelectric Power Plant

Source: Tennessee Valley Authority, Cherokee, ND. Digital Image.
Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/Cherokee-Reservoir (accessed June 13, 2019).

Figure 17-3 shows a typical turbine hall for a Francis-type hydropower turbine. The generator is located above the turbine and it connected to the same shaft.

Figure 17-3 — Typical Hydroelectric Power Turbine Hall

Source: Tennessee Valley Authority, Raccoon Mountain, ND. Digital Image.
Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/Raccoon-Mountain (accessed July 8, 2019).

17.1.1 Offsite Requirements

The cost estimate assumes an allowance for a one-mile transmission line.

17.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $5316/kW. Table 17-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach. In addition to EPC contract costs, the estimate includes owner's costs that cover owner's services, project development costs, studies, permitting, legal, project management, owner's engineering, and start-up and commissioning.

Table 17-1 — Case 17 Capital Cost Estimate

Case 17 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Hydroelectric Power Plant** New Stream Reach Development	
	Units		
Plant Characteristics			
Net Power Rating	MW	100	
Head	ft	75	
Capital Cost Assumptions			
EPC Fee	% of Project Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (Support buildings only)	acres	2	
Estimated Land Cost	$/acres	10,000	
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	1.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	36	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	72	
Operating Life	years	50	
Cost Components		**Breakout**	**Total**
Direct Costs			
Civil Structural Material and Installation	$	247,865,000	
Mechanical Equipment Supply and Installation	$	73,759,000	
Electrical / I&C Supply and Installation	$	25,094,000	
Direct Cost Subtotal	$		346,718,000
Project Indirects (Note 1)	$		56,686,000
EPC Total Before Fee	$		403,404,000
EPC Fee	$		40,340,400
EPC Subtotal	$		443,744,400

Case 17 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Hydroelectric Power Plant** New Stream Reach Development	
	Units		
Owner's Cost Components			
Owner's Services	$	38,351,000	
Land	$	20,000	
Electrical Interconnection	$	1,200,000	
Owner's Cost Subtotal	$		39,571,000
Project Contingency	$	48,332,000	48,332,000
Total Capital Cost	**$**		**531,647,400**
	$/kW net		**5,316**
Capital Cost Notes			
1. Engineering, procurement, scaffolding, project services, construction management, field engineering, and startup and commissioning using EPC contracting.			
2. Project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Excluded: Allowance for Funds Used During Construction, escalation excluded.			

17.3 O&M COST ESTIMATE

The O&M cost estimate incorporates the annual cost of the onsite O&M staff as well as contracted services for grounds keeping and computer maintenance. The estimate also covers the maintenance of the dam, spillway, penstock, turbine, generator, and BOP. The need for various consumables and replacement parts are also considered. The annual cost of consumables, such as lubricants, filters, chemicals, etc., is estimated as a fixed amount, so the variable cost component is considered to be zero. Total annual O&M costs for the New Stream Reach Development 100-MW hydroelectric power plant are summarized in Table 17-2.

Table 17-2 — Case 17 O&M Cost Estimate

Case 17 EIA – Non-Fuel O&M Costs – 2019 $s		
Hydroelectric Power Plant		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**29.86 $/kW-yr**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		

17.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Hydroelectric plants do not produce regulated environmental emission. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 18. BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH

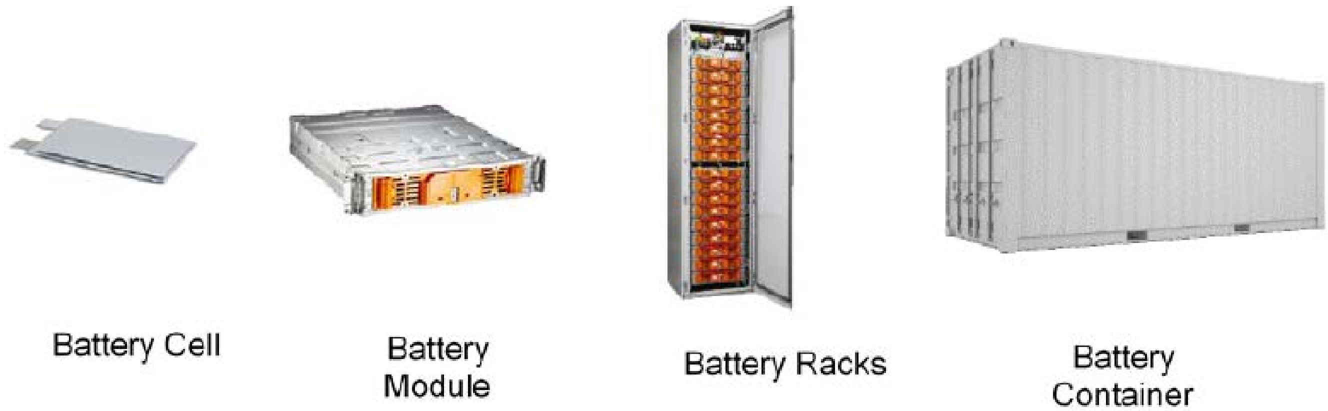
18.1 CASE DESCRIPTION

This case consists of a utility-scale, lithium-ion, battery energy storage system (BESS) with a 50-MW power rating and 200-MWh energy rating; the system can provide 50 MW of power for a four-hour duration. Case 18 assumes that the BESS will be constructed close to an existing potential interconnection point such as grid or generator substation. The cost estimate includes a substation consisting of a transformer to step up from the BESS system to the interconnection voltage (480 V to 13.8 kV) and associated switchgear.

The BESS consists of 25 modular, pre-fabricated battery storage container buildings that contain the racks and appurtenances to store the initial set of batteries and accommodate battery augmentation for the life of the project. The BESS uses utility-scale lithium-ion batteries. Approximately 3% of the initial battery capacity is assumed to degrade each year and require augmentation by the addition of new batteries. (The augmentation cost is included with the annual O&M as discussed in Section 18.3.) Each battery container is equipped with fire detection and suppression systems and HVAC monitoring and control systems. The pre-fabricated battery containers are approximately 40 feet long x 10 feet wide x 8 feet high. Each battery container has an associated inverter-transformer building, which is approximately 20 feet long x 10 feet wide x 8 feet high. The inverter-transformer building houses the inverters, transformers, and associated electrical equipment for each battery container. There is one control building with approximate dimension of 20 feet long x 10 feet wide x 8 feet high to support O&M activities. Each building is set on a concrete slab foundation.

Figure 18-1 shows a typical utility-scale lithium-ion battery. Several battery cells make a battery module, which is independently monitored and controlled. Several battery modules are contained in a battery rack, and there are several battery racks in a battery container.

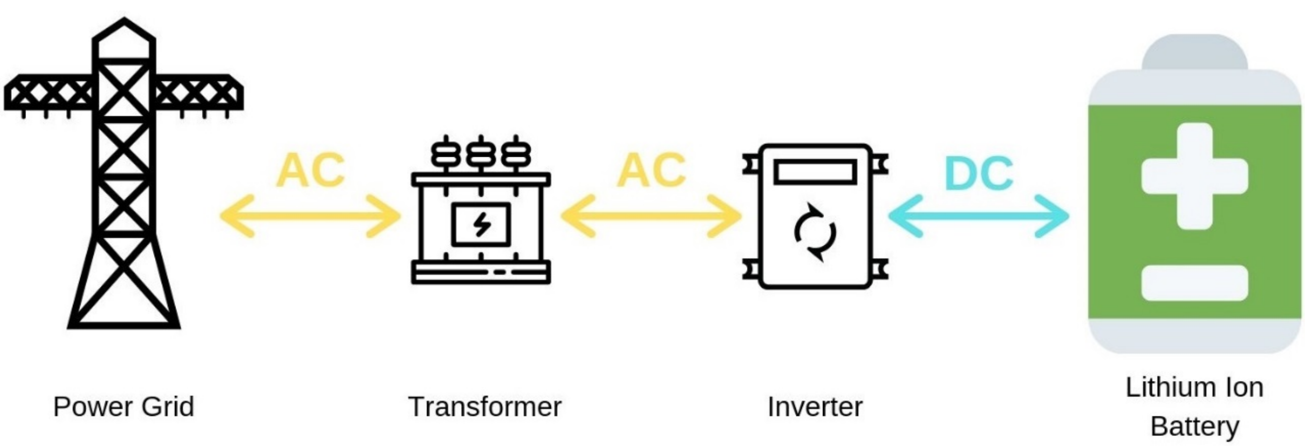
Figure 18-1 — Utility-Scale Lithium-Ion Batteries



Source: National Renewable Energy Laboratory (NREL) "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark, Technical Report NREL/TP-6A20-71714, November 2018. (https://www.nrel.gov/docs/fy19osti/71714.pdf) (accessed July 23, 2019)

The BESS is equipped with 200 MWh of lithium-ion batteries connected in strings and twenty-five 2-MW inverters. Battery energy storage systems are DC systems; however, most electric power generation is produced and distributed as AC power. The BESS is equipped with a power conversion system to convert between AC power for charging and distribution and DC power for storage. The power conversion system includes transformers and associated switchgear that supports battery charging and discharging by converting power between 13.8 kV and 480 V-direct-current. Power is provided by the BESS at a three-phase output voltage of 480 AC. The output voltage is stepped up by a transformer to 34.5 kV and connects to the grid at a substation. This interconnecting substation is not part of the project.

Figure 18-2 — BESS Flow Diagram

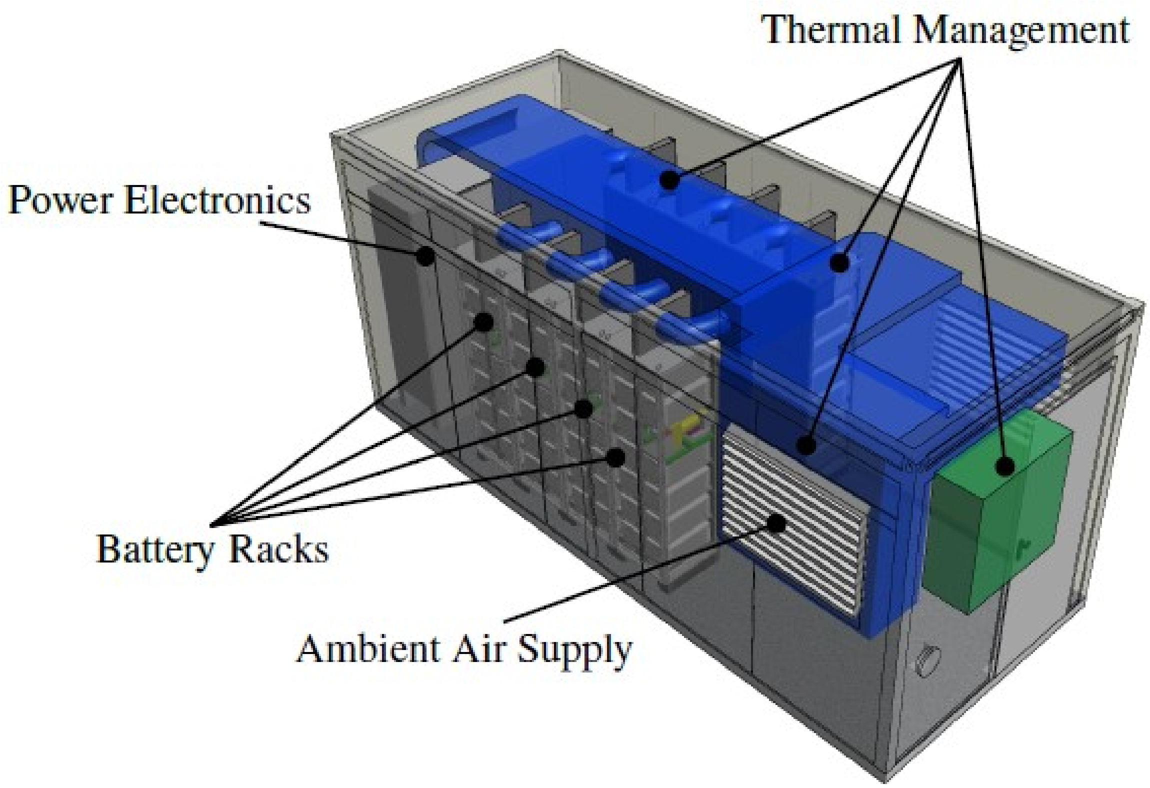


Each battery container is equipped with electronic protection such as current limiters, sensors, and disconnect switches to isolate strings of batteries. The BESS is equipped with multiple levels of monitoring and controls. Each battery module and battery string are monitored and can be controlled by its Battery Management Unit and Battery String Management Unit, respectively. The power conversion system is also monitored and controlled.

The BESS site is equipped with a Supervisory Control and Data Acquisition (SCADA) system that collects performance data from the Battery Management Units, Battery String Management Units, and power conversion system. The BESS can be monitored and controlled remotely through the SCADA system. Some BESS site may be programmed to respond to conditions in the grid through the SCADA system.

Figure 18-3 shows a cut-away view of a typical battery storage container.

Figure 18-3 — Typical Battery Storage Container



Source: Office of Scientific and Technical Information – U.S. Department of Energy, ND. Digital Image. Retrieved from OSTI.gov, https://www.osti.gov/biblio/1409737 (accessed July 15, 2019).

18.1.1 Offsite Requirements

Typically, BESS projects are built at the site of existing generators or near substations where the system can easily tie into a grid for charging and discharging power. This cost estimate includes an allowance for a substation consisting of a transformer to step up to the distribution voltage (480 V to 13.8 kV), associated switchgear, and transmission line to nearby tie-in so that the BESS can receive and distribute 13.8 kV-alternating current power.

The capital cost estimate assumes that road access is available and does not include the cost to build roads. Our cost estimate does not include an allowance for onsite storage of tools, chemicals, or other O&M necessities. The O&M cost estimate assumes the O&M contractor will bring all necessities to the BESS site.

18.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1389/kW or $347/kWh. Both the $/kW and $/kWh are provided to clearly describe the system estimate. Table 18-1 summarizes the cost components for this case. The capital cost estimate is based on a BESS with a power rating of 50 MW and energy rating of 200 MWh (equivalent to a four-hour rating). The cost estimate includes civil works, foundations, buildings, electrical equipment and related equipment, substation, switchyard, transformers, transmission lines, cabling, controls, and instrumentation.

Table 18-1 — Case 18 Capital Cost Estimate

Case 18 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Battery Energy Storage System** 50 MW | 200 MWh Greenfield
Battery Type		Lithium-ion
Service Life		10 years
Total Charging Cycles in Service Life		3,000
	Units	
Plant Characteristics		
Power Rating	MW	50
Energy Rating	MWh	200
Duration	hour	4
Capital Cost Assumptions		
EPC Contracting Fee	% of Project Costs	5%
Project Contingency	% of Project Costs	5%
Owner's Services	% of Project Costs	4%
Estimated Land Requirement	acre	2
Estimated Land Cost	$/acre	30,000

Case 18 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Battery Energy Storage System 50 MW | 200 MWh Greenfield	
Battery Type		Lithium-ion	
Service Life		10 years	
Total Charging Cycles in Service Life		3,000	
	Units		
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	0.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	4	
Plant Construction Time	months	6	
Total Lead Time Before COD	months	10	
EPC Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		8,314,000
Batteries	$	40,037,000	
Inverters	$	5,237,000	
Grounding Wiring, Lighting, Etc.	$	254,000	
Transformers	$	533,000	
Cable	$	618,000	
Electrical Subtotal	$		46,679,000
Raceway, Cable tray & Conduit	$	258,000	
Control & Instrumentation	$	22,000	
Transformer Switchgear, Circuit Breaker & Transmission Line	$	305,000	
Other Equipment & Material Subtotal	$		585,000
Project Indirects	$		4,595,000
EPC Total Before Fee	$		60,173,000
EPC Fee	$		3,009,000
EPC Subtotal	$		63,182,000
Owner's Cost Components (Note 2)			
Owner's Services	$		2,906,000
Land	$		60,000
Electrical Interconnections (Note 3)	$		0
Owner's Cost Subtotal	$		2,966,000
Project Contingency	$		3,308,000
Total Capital Cost	**$**		**69,456,000**
	$/kW net		**1,389**
	$/kWh		**347**

Capital Cost Notes

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.
3. The BESS is assumed to be located sufficient close to an existing substation, such that any transmission costs are covered in the project electrical equipment cost. A separate electric transmission cost is not necessary.

18.3 O&M COST ESTIMATE

The O&M cost estimate considers the ongoing O&M cost through the life of a BESS project. The service life of a BESS depends on how it is used. This case assumes that the BESS will have a service life of 3000 full charge-discharge cycles, which is a relatively typical basis in the industry. A full charge-discharge cycle occurs when a battery is fully charged, demand requires the full discharge of the energy, and then the battery is fully charged again. A service life of 3000 full cycles in a 10-year period equates to slightly fewer than 1 cycle per day. BESS projects that serve ancillary markets may not experience full charge and discharge cycle every day or may experience partial charge cycles. and The BESS service life depends on the charge and discharge pattern; therefore, a system that experiences partial charge cycles or multiple full cycles each day will have a different service life than described. The 3000 full-cycle service life is a typical industry basis to determine the cost and technical specifications for an energy storage system.

Many BESS projects engage a third-party contractor to conduct regular O&M activities. This cost estimate considers the cost of such contracted services, which include remote monitoring of the system, periodic onsite review of equipment conditions and cable connections, grounds maintenance, and labor involved in battery augmentation. During the service life of a BESS, a percentage of the batteries are expected to significantly decrease in efficiency or stop functioning. Instead of removing and replacing those batteries, BESS are designed with excess racking to accommodate additional batteries to augment the lost capacity. The entire BESS will be removed when it is decommissioned at the end of its service life. This approach reduces the costs associated with removing and transporting failed batteries each year. Typically, BESS designs estimate that approximately 3% of the battery capacity will be needed to be augmented each year. This O&M cost estimate uses the 3% battery augmentation factor and incorporates that cost in the annual fixed O&M cost. The O&M cost include an annual allowance for G&A costs. The fixed O&M costs are $24.80/kW-year. The variable costs are $0.00/MWh, since there are no consumables linked to energy output. Augmentation is included with fixed cost in this case since the case assumes the same number of charging cycles each year during the service life of the project.

The O&M costs do not include the cost of energy to charge the system.

Table 18-2 — Case 18 O&M Cost Estimate

Case 18 EIA – Non-Fuel O&M Costs – 2019 $s		
Battery Energy Storage System - 50 MW | 200 MWh - Greenfield		
Fixed O&M – Plant (Note 1)		
General & Administrative and Contract Services (Remote monitoring, on-site O&M, battery augmentation labor, grounds keeping, etc.)	$/year	70,000
Battery Augmentation	$/year	1,170,000
Subtotal Fixed O&M	$/year	1,240,000
$/kW-year	$/kW-year	**24.80 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. All costs tied to energy produced are covered in fixed cost.		

18.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Battery energy storage systems do not produce regulated environmental emission. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 19. BATTERY ENERGY STORAGE SYSTEM, 50 MW / 100 MWH

19.1 CASE DESCRIPTION

This case is nearly identical to Case 18 with the exception that this is a BESS system with half the energy rating (100 MWh) and therefore half the duration (two hours). Since the energy rating for this case is half of Case 18, there will be half as many batteries. Therefore, this case will also have half as many battery containers. Case 19 assumes lithium-ion batteries are used, and the cost of civil works, foundations, buildings, electrical equipment and related equipment, substation, switchyard, transformers, transmission lines, cabling, and controls and instrumentation are included in the cost estimate. Case 19 assumes 3% of the initial set of batteries will require augmentation each year.

Refer to Case 18 for a more in-depth description of BESSs.

19.1.1 Offsite Requirements

Typically, BESS projects are built at the site of existing generators or near substations where the system can easily tie into a grid for charging and discharging power. This cost estimate includes an allowance for a substation consisting of a transformer to step up to the distribution voltage (480 V to 13.8 kV), associated switchgear, and transmission line to nearby tie-in so that the BESS can receive and distribute 13.8 kV-alternating current power.

19.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $845/kW or $423/kWh. Both the $/kW and $/kWh are provided to clearly describe the system estimate. Table 19-1 summarizes the cost components for this case. The capital cost estimate is based on a BESS with a power rating of 50 MW and energy rating of 100 MWh. Therefore, the BESS provides 50 MW of power for a duration of two hours. The capital cost estimate is based on an EPC contracting approach.

Typical project-related costs are included, such as owner’s services, project development costs, studies, permitting, legal, project management, owner’s engineering, and start-up and commissioning.

Table 19-1 — Case 19 Capital Cost Estimate

Case 19 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Battery Energy Storage System 50 MW | 100 MWh Greenfield	
Battery Type		Lithium-ion	
Service Life		10 years	
Total Charging Cycles in Service Life		3,000	
	Units		
Plant Characteristics			
Power Rating	MW	50	
Energy Rating	MWh	100	
Duration	hour	2	
Capital Cost Assumptions			
EPC Contracting Fee	% of Project Costs	5%	
Project Contingency	% of Project Costs	5%	
Owner's Services	% of Project Costs	4%	
Estimated Land Requirement	acre	1.2	
Estimated Land Cost	$/acre	30,000	
Electric Interconnection Costs (Note 1)			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	0.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	4	
Plant Construction Time	months	5	
Total Lead Time Before COD	months	9	
Cost Components (Notes 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,071,000
Batteries	$	20,019,00	
Inverters	$	5,237,000	
Grounding Wiring, Lighting, Etc.	$	143,000	
Transformers	$	533,000	
Cable	$	370,000	
Electrical Equipment Subtotal	$		26,302,000
Raceway, Cable tray & Conduit	$	155,000	
Control & Instrumentation	$	22,000	
Transformer Switchgear, Circuit Breaker & Transmission Line	$	305,000	
Other Equipment & Material Subtotal	$		482,000
Project Indirects	$		3,679,000
EPC Total Before Fee	$		36,534,000
EPC Fee	$		1,827,000
EPC Subtotal	$		38,361,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,850,000
Land	$		36,000
Electrical Interconnection Cost (Note 3)	$		0
Owner's Cost Subtotal	$		1,886,000
Project Contingency	$		2,013,000
Total Capital Cost	**$**		**42,260,000**
	$/kW net		**845**
	$/kWh		**423**

Case 19 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Battery Energy Storage System** 50 MW | 100 MWh Greenfield
Battery Type	Lithium-ion
Service Life	10 years
Total Charging Cycles in Service Life	3,000
Capital Cost Notes	
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs. 3. The BESS is assumed to be located sufficient close to an existing substation, such that any transmission costs are covered in the project electrical equipment cost. A separate electric transmission cost is not necessary.	

19.3 O&M COST ESTIMATE

The O&M cost estimate considers the ongoing O&M cost through the life of a BESS project. As mentioned in Case 18, the service life of a BESS depends on how it is used. This case assumes that the BESS will have a service life of 3000 full charge-discharge cycles, which is a relatively typical basis in the industry. A full charge-discharge cycle occurs when a battery is fully charged, demand requires the full discharge of the energy, and then the battery is fully charged again. A service life of 3000 full cycles in a 10-year period equates to slightly fewer than 1 cycle per day. BESS projects that serve ancillary markets may not experience a full charge and discharge cycle every day or may experience partial charge cycles. The BESS service life depends on the charge and discharge pattern; therefore, a system that experience partial charge cycles or multiple cull cycles each day will have a different service life than described. The service life of 3000 full cycles is a typical industry basis to determine the cost and technical specifications for an energy storage system.

Many BESS projects engage a third-party contractor to conduct regular O&M activities. This cost estimate considers the cost of such contracted services, which include remote monitoring of the system, periodic onsite review of equipment conditions and cable connections, grounds maintenance, and labor involved in battery augmentation. During the service life of a BESS, a percentage of the batteries are expected to significantly decrease in efficiency or stop functioning. Instead of removing and replacing those batteries, BESS are designed with excess racking to accommodate additional batteries to augment the lost capacity. This approach reduces the costs associated with removing and transporting failed batteries each year. Typically, BESS designs estimate that approximately 3% of the total number of batteries installed will need to be augmented each year. The entire BESS will be removed when it is decommissioned at the end of its service life. This O&M cost estimate uses the 3% battery augmentation factor and incorporates that cost in the annual fixed O&M cost. The O&M cost includes an annual allowance for G&A costs. The fixed costs are $12.90/kW-year. The variable costs are $0.00/MWh, since there are no consumables linked to energy output. Augmentation is included with fixed cost in this case since the case assumes the same number of charging cycles each year during the service life of the project.

The O&M costs do not include the cost of energy to charge the system.

Table 19-2 — Case 19 O&M Cost Estimate

Case 19 EIA – Non-Fuel O&M Costs – 2019 $s		
Battery Energy Storage System - 50 MW | 100 MWh – Greenfield		
Fixed O&M – Plant (Note 1)		
General & Administrative and Contract Services (Remote monitoring, on-site O&M, battery augmentation labor, grounds keeping, etc.)	$/year	60,000
Battery Augmentation	$/year	<u>585,000</u>
Subtotal Fixed O&M	$/year	645,000
$/kW-year	$/kW-year	**12.90 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. All costs tied to energy produced are covered in fixed cost.		

19.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Battery energy storage systems do not produce regulated environmental emission. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 20. ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW

20.1 CASE DESCRIPTION

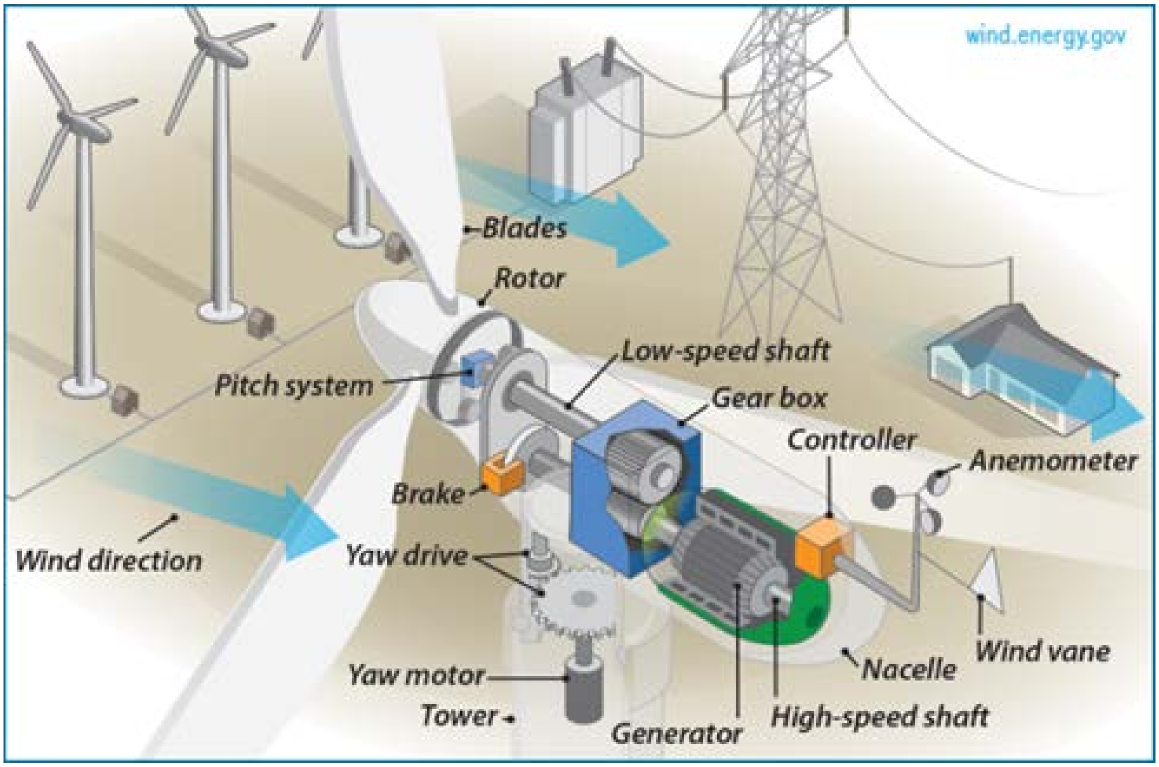
This case is an onshore wind power project located in the Great Plains region of the United States with a total project capacity of 200 MW. The Great Plains region, reflective of the central United States, has an abundance of land that is suitable for wind turbine siting and is generally not subject to land constraints that would otherwise limit project size.

20.2 MECHANICAL EQUIPMENT & SYSTEMS

This Great Plains region onshore wind project is based on a 200 MW total project capacity. Parameters that affect project cost and performance include turbine nameplate capacity, rotor diameter, and hub height. The case configuration assumes 71 wind turbines with a nominal rating of 2.8 MW with a 125-meter rotor diameter, and a 90-meter hub height. These features reflect modern wind turbines that employ larger rotor diameter and greater hub heights. The primary advantage of taller hub heights and larger rotor diameters include access to better wind profiles at higher altitudes and increased turbine swept area, enabling the unit to capture more energy.

Wind turbine generators convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine used for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator located inside of the nacelle, which is the housing positioned atop the wind turbine tower.

Figure 20-1 — Wind Turbine Generator Drivetrain



Source: Office of Energy Efficiency & Renewable Energy, Wind Energy Technologies Office – U.S. Department of Energy, *windTurbineLabels*, ND. Digital Image (Image 1 of 17).
Retrieved from Energy.gov, https://www.energy.gov/eere/wind/inside-wind-turbine (accessed May 31, 2019).

20.2.1 Electrical & Control Systems

Each wind turbine generator (WTG) consists of a doubly-fed induction generator. The low-voltage output from the generator is stepped up to medium voltage through a transformer located either in the nacelle or at the tower base. A medium voltage collection system conveys the generated energy to an onsite substation that further steps up the voltage for interconnection with the transmission system with a voltage of 230 kV.

A SCADA system is provided for communications and control of the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind project as a whole.

20.2.2 Offsite Requirements

Wind projects harness power from wind and therefore do not require fuel or fuel infrastructure. The offsite requirements are limited to construction of site and wind turbine access roads, the O&M building, and electrical interconnection to the transmission system.

20.3 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1265/kW. Table 20-1 summarizes the cost components for this case.

Capital cost were broken down into the following categories:

- **Civil/Structural Costs:** These costs include the WTG spread footing and substation foundations, access roads, crane pads, road improvements, and O&M building.
- **Mechanical Costs:** These costs include the purchase price for the WTGs from the OEM (i.e., blades, hub, drivetrain, generator, tower, and electronics), transportation and delivery to the project site, and assembly and erection on site.
- **Electrical Costs:** These costs include pad-mounted transformers, underground collection system, and the project substation.
- **Project Indirect Costs:** These costs include construction management, engineering, and G&A costs.
- **EPC Fee:** The EPC fee is a markup charged by the construction contractor.
- **Project Contingency Costs:** Contingency is an allowance considered to cover the cost of undefined or uncertain scope of work, including EPC change orders or costs associated with schedule delays.
- **Owner Costs:** These costs include Project development costs that cover project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access and permitting. However, estimates exclude project financing costs.

Table 20-1 — Case 20 Capital Cost Estimate

Case 20 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Onshore Wind – Large Plant Footprint: Great Plains Region** 200 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Plant Characteristics		
Net Plant Capacity	MW	200
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	8%
Project Contingency	% of Project Costs	4%
Owner's Services	% of Project Costs	7%
Electric Interconnection Costs		
Transmission Line Cost	$/mile	1,200,000
Miles	miles	1.00

Case 20 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Onshore Wind – Large Plant Footprint: Great Plains Region** 200 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Typical Project Timelines		
Development, Permitting, Engineering	months	12
Plant Construction Time	months	9
Total Lead Time Before COD	months	21
Operating Life	years	25
Cost Components (Note 1)		**Total**
Civil/Structural/Architectural Subtotal	$	24,297,000
WTG Procurement and Supply	$	155,209,000
WTG Erection	$	7,502,000
Mechanical Subtotal	$	162,711,000
Electrical – Substation Electrical Equipment	$	7,679,000
Electrical – Pad Mount Transformers and Collection System	$	10,711,000
Electrical Subtotal	$	18,390,000
Project Indirects	$	5,183,000
EPC Total Before Fee	$	210,581,000
EPC Fee	$	16,846,000
EPC Subtotal	$	227,427,000
Owner' Cost Components (Note 2)		
Owner's Cost Subtotal	$	15,919,890
Project Contingency	$	9,734,000
Total Capital Cost	**$**	253,080,890
	$/kW net	**1,265**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.		

20.4 O&M COST ESTIMATE

O&M cost estimates reflect a full-service agreement arrangement under which an O&M contractor provides labor, management, and parts replacement (including unscheduled parts replacement) for the WTGs, collection system, and substation. Our cost estimate excludes site-specific owner's costs such as land lease royalties, property taxes, and insurance. However, average land lease cost in Great Plains region is $2.84/kW-yr. Table 20-2 summarizes the average annual O&M expenses projected for an assumed 25-year project life.

Table 20-2 — Case 20 O&M Cost Estimate

Case 20 EIA – Non-Fuel O&M Costs – 2019 $s		
Onshore Wind – Large Plant Footprint: Great Plains Region		
Fixed O&M – Plant (Note 1)		
WTG Scheduled Maintenance	$/year	2,294,000
WTG Unscheduled Maintenance	$/year	2,167,000
Balance of Plant Maintenance	$/year	806,000
Subtotal Fixed O&M	$/year	5,267,000
$/kW-year	$/kW-year	**26.34 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs.		
2. O&M Costs estimates reflect Full Service Agreement and exclude site specific owner's costs such as land lease, royalties, property taxes, and insurance. Average land lease costs in Great Plains region is $2.80/kW-year.		
3. Average FSA term considered: 25 years		

20.5 ENVIRONMENTAL & EMISSIONS INFORMATION

Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 21. ONSHORE WIND, SMALL PLANT FOOTPRINT, 50 MW

21.1 CASE DESCRIPTION

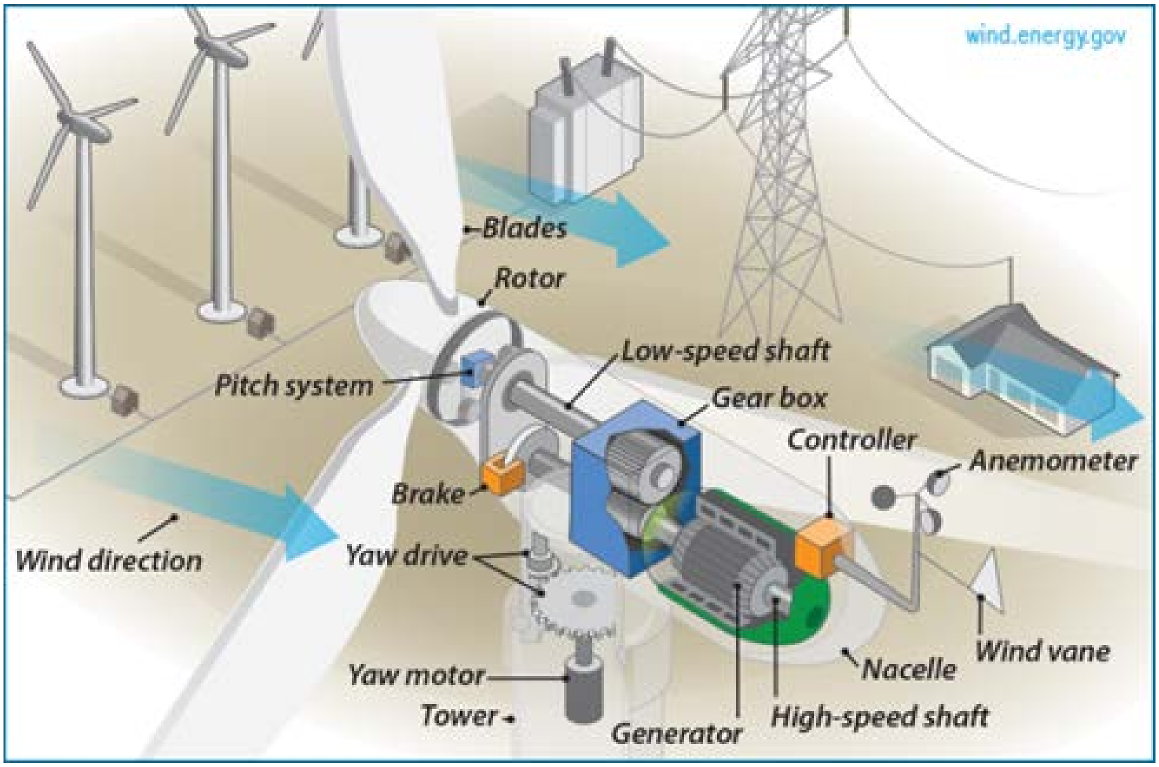
This case is an onshore wind project with a total project capacity of 50 MW. "Coastal" refers to the area that is reflective of the Mid-Atlantic, Northeast, and Pacific regions of the United States. Due to assumed land availability constraints for this region, the project capacity is limited.

21.1.1 Mechanical Equipment & Systems

The onshore wind project in the Coastal region is based on a 50-MW total project capacity. Parameters that affect project cost and performance include turbine nameplate capacity, rotor diameter, and hub height. The case configuration assumes 17 wind turbines with a nominal rating of 2.8 MW with 125-meter rotor diameters and 90-meter hub heights. These features reflect modern wind turbines that employ larger rotor diameter and greater hub heights. The primary advantage of taller hub heights and larger rotor diameters include access to better wind profiles at higher altitudes and increased turbine swept area, enabling the unit to capture more energy.

Wind turbine generators convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine used for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator located inside of the nacelle, which is the housing positioned atop the wind turbine tower.

Figure 21-1 — Wind Turbine Generator Drivetrain



Source: Office of Energy Efficiency & Renewable Energy, Wind Energy Technologies Office – U.S. Department of Energy, *windTurbineLabels*, ND. Digital Image (Image 1 of 17).
Retrieved from Energy.gov, https://www.energy.gov/eere/wind/inside-wind-turbine (accessed May 31, 2019).

21.1.2 Electrical & Control Systems

Each WTG consists of a doubly-fed induction generator. The low-voltage output from the generator is stepped up to medium voltage through a transformer located either in the nacelle or at the tower base. A medium voltage collection system conveys the generated energy to an onsite substation that further steps up the voltage for interconnection with the transmission system with a voltage of 230 kV.

A SCADA system is provided for communications and control of the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind project as a whole.

21.1.3 Offsite Requirements

Wind projects harness power from wind and therefore do not require fuel or fuel infrastructure. The offsite requirements are limited to construction of site and wind turbine access roads, the O&M building, and electrical interconnection to the transmission system.

21.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1677/kW. Table 21-1 summarizes the cost components for this case.

Capital cost estimates were broken down into the following categories:

- **Civil/Structural Costs:** These costs include the WTG spread footing and substation foundations, access roads, crane pads, road improvements, and O&M building.
- **Mechanical Costs:** These costs include the purchase price for the WTGs from the OEM (blades, hub, drivetrain, generator, tower, and electronics), transportation and delivery to the project site, and assembly and erection on site.
- **Electrical Costs:** These costs include pad-mounted transformers, collection system, and project substation.
- **Project Indirect Costs:** These costs include construction management, engineering, and G&A costs.
- **EPC Fee:** The EPC fee is a markup charged by the construction contractor.
- **Project Contingency Costs:** Contingency is an allowance considered to cover the cost of undefined or uncertain scope of work, including EPC change orders or costs associated with schedule delays.
- **Owner Costs:** These costs include Project development costs that cover project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access, and permitting. However, estimates exclude project financing costs.

Table 21-1 — Case 21 Capital Cost Estimate

Case 21 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Onshore Wind – Small Plant Footprint: Coastal Region** 50 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Plant Characteristics		
Net Plant Capacity	MW	50
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	8%
Project Contingency	% of Project Costs	6%
Owner's Services	% of Project Costs	10%
Electric Interconnection Costs		
Transmission Line Cost	$/mile	1,200,000
Miles	miles	1.00

Case 21 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Onshore Wind – Small Plant Footprint: Coastal Region** 50 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Typical Project Timelines		
Development, Permitting, Engineering	months	12
Plant Construction Time	months	6
Total Lead Time Before COD	months	18
Operating Life	years	25
Cost Components (Note 1)		**Total**
Civil/Structural/Architectural Subtotal	$	10,529,000
WTG Procurement and Supply	$	44,881,000
Turbine Erection	$	3,539,000
Mechanical Subtotal	$	48,419,000
Electrical – Substation Electrical Equipment	$	510,000
Electrical – Pad Mount Transformers and Collection System	$	3,495,000
Electrical Subtotal	$	6,005,000
Project Indirects	$	1,618,000
EPC Total Before Fee	$	66,571,000
EPC Fee	$	5,326,000
EPC Subtotal	$	71,897,000
Owner's Cost Subtotal (Note 2)	$	7,189,700
Project Contingency	$	4,745,000
Total Capital Cost	**$**	83,831,700
	$/kW net	**1,677**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.		

21.3 O&M COST ESTIMATE

O&M cost estimates reflect a full-service agreement arrangement, under which an O&M contractor provides labor, management, and parts replacement (including unscheduled parts replacement) for the WTGs, collection system, and substation. Our cost estimates exclude site specific owner's costs such as land lease royalties, property taxes and insurance. However, average land lease costs in Coastal region is $3.60/kW-yr. Table 21-2 summarizes the average annual O&M expenses projected for an assumed 25-year project life.

Table 21-2 — Case 21 O&M Cost Estimate

Case 21 EIA – Non-Fuel O&M Costs – 2019 $s		
Onshore Wind – Small Plant Footprint: Coastal Region		
Fixed O&M – Plant ($/kW-year) (Note 1)		
WTG Scheduled Maintenance	$/year	765,000
WTG Unscheduled Maintenance	$/year	723,000
Balance of Plant Maintenance	$/year	269,000
Subtotal Fixed O&M	$/year	1,757,000
$/kW-year	$/kW-year	**35.14 $/kW-year**
Variable O&M ($/MWh) (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs.		
2. O&M Costs estimates reflect Full Service Agreement and exclude site specific owner's costs such as land lease, royalties, property taxes and insurance. Average land lease costs in Coastal region is $3.60/kW-year.		
3. Average FSA term considered: 25 years		

21.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 22. OFFSHORE WIND, 400 MW

22.1 CASE DESCRIPTION

This case is an offshore wind project with a total 400-MW project capacity. The case configuration assumes wind turbines rated at 10 MW each, located 30 miles offshore in waters with a depth of 100 feet, and assumes a five-mile onshore cable run.

22.1.1 Mechanical Equipment & Systems

The offshore wind project is based on a total project capacity of 400 MW. Parameters that affect project cost and performance include project size, turbine nameplate capacity, water depth, and distance to shore. The case configuration assumes wind turbines rated at 10 MW each. They are located 30 miles offshore in waters with a 100-foot depth. An onshore cable run of five miles is also assumed.

For the purposes of this study, it has been assumed that wind turbines installed employ fixed-type foundation structures; monopile substructures were taken into consideration. Generally, these are installed in relatively shallow waters, not exceeding 150 feet, consistent with our assumption. Water depth and distance to shore has a significant impact on the cost of fixed foundation structure due to the expenses related to cable lengths and installation costs.

Wind turbine generators convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine used for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator located inside of the nacelle, which is the housing positioned atop the wind turbine tower.

22.1.2 Electrical & Control Systems

Each wind turbine consists of a doubly-fed induction generator with high-speed electrical slip rings that produces electricity from the rotational energy of wind. The converter converts DC to AC. The power collection system collects energy from all the wind turbines and increases the voltage to 33–66 kV through a dedicated transformer at the WTG. Array cables, which are buried in the sea floor, transmit electricity to the offshore substation where the voltage is increased to 138 kV. It is then transmitted to an onshore substation via export cables. The power from this substation is supplied for interconnection with the transmission system.

A SCADA system is responsible for communications between the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind project as a whole.

22.1.3 Offsite Requirements

Since wind is a clean source of energy, scope of offsite works is limited to construction of offshore-to-shore submarine cables, port infrastructures, installation vessels (construction and cable laying) and electrical interconnection to the transmission system.

22.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $4375/kW. Table 22-1 summarizes the cost components for this case.

Capital cost estimates were broken down into the following categories:

- **Civil/Structural Costs:** These costs include the port staging, WTG, and offshore substation foundations.
- **Mechanical Costs:** These costs include the purchase price for the WTGs from the OEM. This price includes the cost of the WTG equipment (blades, hub, drivetrain, generator, tower, and electronics), support vessels, transportation and delivery to port, and erection on site.
- **Electrical Costs:** These cost include interconnection, offshore and onshore transmission that includes inter array cabling, export cabling, and substations.
- **Project Indirect Costs:** These costs include construction management, engineering, and G&A costs.
- **EPC Fee:** The EPC fee is a markup charged by the construction contractor.
- **Project Contingency Costs:** Contingency is an allowance considered to cover the cost of undefined or uncertain scope of work, including EPC change orders or costs associated with schedule delays.
- **Owner Costs:** These costs include Project development costs that cover project feasibility analyses, wind resource assessments, offshore geotechnical and environmental loading studies, obtaining offshore leases, transmission access, and permitting. However, the estimates exclude project financing costs.

Table 22-1 — Case 22 Capital Cost Estimate

Case 22 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Fixed-bottom Offshore Wind: Monopile Foundations** 400 MW | 10 MW WTG
Offshore Cable Length (mi)		30
Onshore Cable Length (mi)		5
Water Depth (ft)		100
	Units	
Plant Characteristics		
Net Plant Capacity	MW	400
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	5%
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	12
Total Lead Time Before COD	months	36
Operating Life	years	25
Cost Components (Note 1)		**Total**
Civil/Structural/Architectural Subtotal	$	240,648,000
WTG Procurement and Supply	$	653,008,000
WTG Assembly/Installation	$	125,792,000
Mechanical Subtotal	$	778,800,000
Interconnection	$	60,995,000
Offshore Transmission & eBOP	$	213,947,000
Onshore Transmission	$	60,172,000
Electrical Subtotal	$	335,114,000
Project Indirects	$	74,800,000
EPC Total Before Fee	$	1,429,362,000
EPC Fee	$	85,762,000
EPC Subtotal	$	1,515,124,000
Owner's Cost Subtotal (Note 2)	$	75,756,200
Project Contingency	$	159,088,000
Total Capital Cost	**$**	1,749,968,200
	$/kW net	**4,375**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.		

22.3 O&M COST ESTIMATE

Operating expenditures cover all maintenance expenses during operations, including management, labor, equipment and vessel rentals, parts, and consumables for both scheduled and unscheduled maintenance of the WTGs and BOP systems, as well as operations monitoring.

Table 22-2 — Case 22 O&M Cost Estimate

Case 22 EIA – Non-Fuel O&M Costs – 2019 $s		
Fixed-bottom Offshore Wind: Monopile Foundations		
Fixed O&M – Plant		
Subtotal Fixed O&M	$/kW-year	**110.00 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**

22.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 23. CONCENTRATING SOLAR PLANT, 100 MW, 8-HR STORAGE

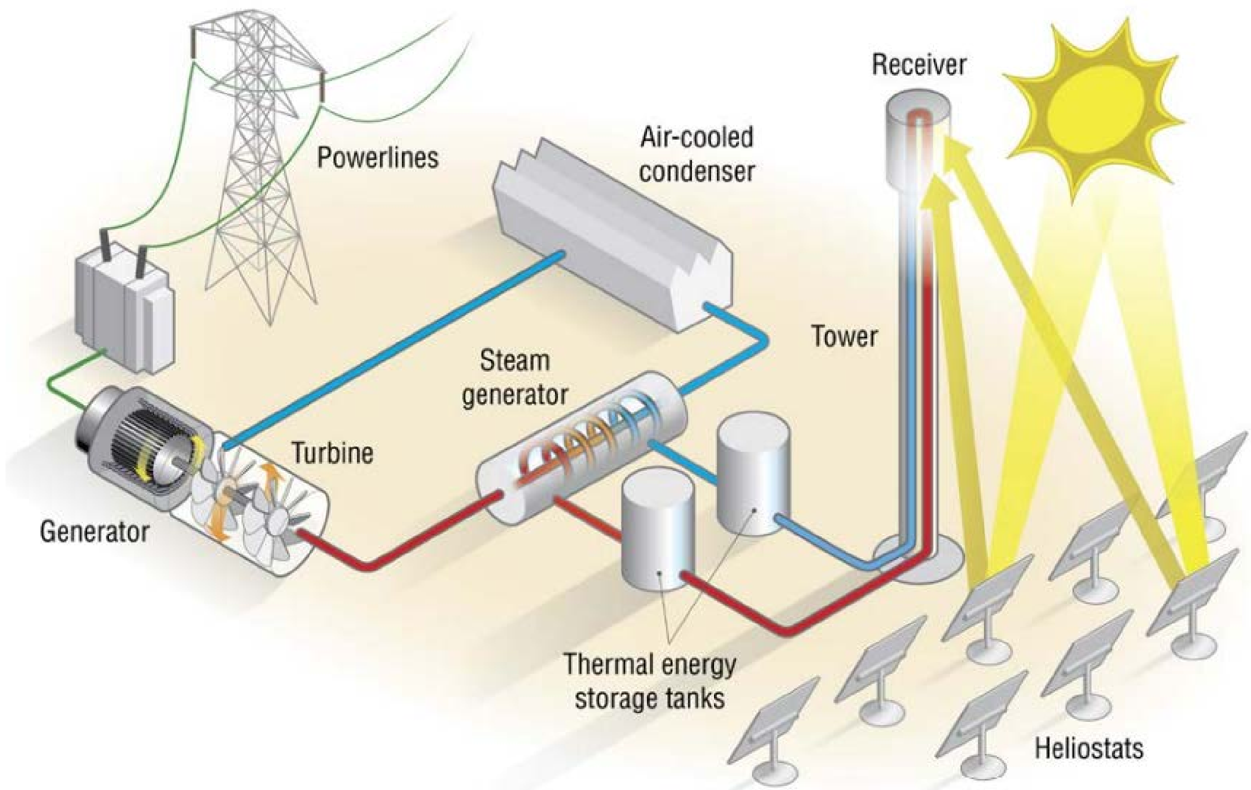
23.1 CASE DESCRIPTION

This case is a concentrating solar thermal power plant (CSP) with eight hours of thermal storage. This type of plant is typically referred to as a "solar power tower" due to the central receiver tower, which is surrounded by a field of reflectors. The solar power tower uses a field of thousands of solar reflectors, called heliostats, to direct solar radiation energy to a central receiver, which is located at the top of the tower. The heliostats can rotate and pitch to direct the sunlight toward the receiver as the sun passes across the horizon.

The plant for this case is rated for 115 MW gross power, and an auxiliary load of approximately 15 MW is expected. Power is generated at 15.5 kV and 60 Hz. It is stepped up to 230 kV for transmission.

Figure 23-1 shows a diagram of the system assumed for this case. The plant is equipped with two molten salt tanks: one hot tank and one cold tank. Molten salt pumps move molten salt from the cold salt tank to the heat exchanger in the receiver where it absorbs energy from the solar radiation concentrated on the surface of the receiver. The hot molten salt flows down the tower to the hot molten salt tank. A molten salt pump from the power block moves molten salt from the hot salt tank through a steam generating heat exchanger to the cold salt tank. Superheated steam is generated in the heat exchanger, which is used to drive a steam turbine to turn a generator. The steam is condensed in an ACC. The plant is equipped with water treatment facilities to support the steam cycle. The plant control system operates both the power block and the solar field. As mentioned, the solar field may consist of thousands of individual heliostat reflectors. Some solar power tower projects include more than 10,000 heliostats. Recent advances in control technology have eliminated the need for control and power cabling to each heliostat. Instead, each heliostat is equipped with a photovoltaic (PV) solar panel and BESS to power the heliostat movement. Each heliostat has a control unit that communicates with a central controller wirelessly.

Figure 23-1 — Concentrating Solar Power Tower System Diagram



Source: U.S. Department of Energy, *2014: The Year of Concentrating Solar Power*, May 2014. PDF.
Retrieved from Energy.gov, https://www.energy.gov/sites/prod/files/2014/10/f18/CSP-report-final-web.pdf (accessed June 13, 2019)

The thermal storage system is based on the amount of “hot” molten salt that is stored in the hot salt tank when the solar resource is no longer available after the sun goes down. The duration of storage is contingent on the amount of hot molten salt and its temperature that can be collected in a “solar day,” which depends on the solar resource available during that time.

Figure 23-2 shows an aerial view of a concentrating solar power tower plant. The central receiver can be seen on the top of a tower surrounded by thousands of heliostats. The ACC and hot and cold molten salt tanks are clearly shown. Buildings that house the control room, work shop, and spare parts warehouse are also shown.

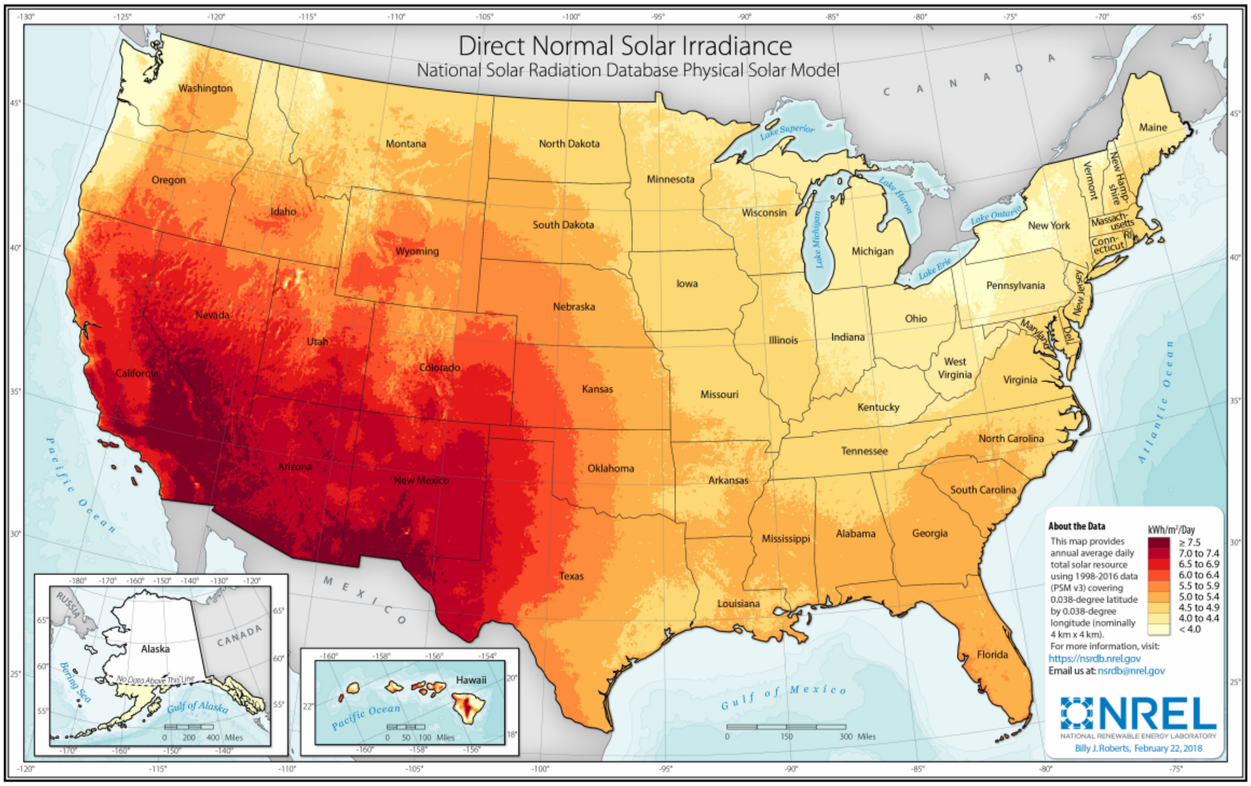
Figure 23-2 — Aerial View of Concentrating Solar Power Tower Project

Crescent Dunes

Source: Loan Programs Office – U.S. Department of Energy, *DOE-LPO_Project-Photos_CSP_Crescent-Dunes_02*, ND. Digital Image. Retrieved from Energy.gov, https://www.energy.gov/lpo/crescent-dunes (accessed June 5, 2019)

Figure 23-3 shows the direct normal solar irradiance across the United States. The solar irradiance is used to determine the best location to capture solar energy.

Figure 23-3 — United States Solar Resource



Source: U.S. Department of Energy, National Renewable Energy Laboratory, *Direct Normal Solar Irradiance,* ND. Retrieved from NREL.gov, https://www.nrel.gov/gis/images/solar/solar_ghi_2018_usa_scale_01.jpg (accessed June 5, 2019).

23.1.1 Offsite Requirements

The cost estimate assumes an allowance for a one-mile transmission line. The estimates include the cost of onsite roads and a connection to an existing nearby highway. The estimate includes the cost of water supply infrastructure onsite; however, potable water and sewer tie-in are nearby.

23.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $7221/kW. Table 23-1 summarizes the cost components for this case. The capital cost is based on the latest cost information for mechanical and electrical components and considerations for implementing the latest available technology.

The cost estimate includes the cost for land, site clearing, civil works, drainage, roads on the plant site, and water supply infrastructure. The complete heliostat field cost includes the reflector, foundation pedestal, supports, and power and controls for each unit. The receiver tower is based on a concrete structure with an internal space for an elevator, molten salt piping, and related equipment. The molten salt circulation system includes the molten salt pumps, piping, heat tracing, insulation, and related controls equipment. The costs consider the construction of the hot and cold molten salt tanks, their foundations, insulation, heat tracing, the molten salt itself, and related equipment. The steam cycle equipment (i.e., the steam generating superheater, ACC, water treatment system, piping, valves, foundation, instrumentation and controls, and all related equipment) are included. All electrical BOP, fire protection equipment, and other equipment and materials needed to complete construction are included in the cost estimate. All labor and equipment needed for construction is included with the cost estimate.

In the past few years, concentrating solar power technology has been implemented in the Middle East more frequently than the United States. Therefore, much of the publicly available cost information indicates a $/installed kW significantly lower than the estimate in this report, which is for a project constructed in the United States. The installed project cost for an identical project in the Middle East (e.g., United Arab Emirates) can be expected to be lower by a significant amount. The lower costs are a result of several factors, including labor cost, which can be nearly half the cost as in the United States[3]; government assistance with financial costs (in the forms of favorable loan programs, low taxes, and other incentives); low profit margins; and aggressive contracting.

The capital cost estimate is based on an EPC contracting approach.

Typical project related costs are included, such as Owner's services, project development costs, studies, permitting, legal, project management, owner's engineering, and start-up and commissioning.

Table 23-1 — Case 23 Capital Cost Estimate

Case 23 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Concentrating Solar Power Tower with Molten Salt Thermal Storage**
	Units	
Plant Characteristics		
Gross Power Rating	MW	115
Net Power Rating	MW	100
Thermal Storage	hr	8
Capital Cost Assumptions		
EPC Contracting Fee	% of Project Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	7%
Estimated Land Requirement	acres	2,000
Estimated Land Cost	$/acre	10,000

[3] https://arstechnica.com/science/2018/10/are-super-cheap-solar-fields-in-the-middle-east-just-loss-leaders/

Case 23 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Concentrating Solar Power Tower with Molten Salt Thermal Storage**
	Units	
Electric Interconnection Costs		
Transmission Line Cost	$/mile	1,200,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	15
Plant Construction Time	months	30
Total Lead Time Before COD	months	33
Operating Life	years	30
Cost Components (Note 1)		**Total**
Direct Costs		
Site Preparation	$	18,474,000
Heliostat Field	$	157,437,000
Tower	$	24,816,000
Receiver	$	74,081,000
Thermal Energy Storage System (TES)	$	65,276,000
Balance of Plant – Steam System	$	11,310,000
Balance of Plant – Electrical, Instrumentation and Controls	$	9,186,000
Balance of Plant – Foundations & Support Structures	$	15,917,000
Power Block (Steam Turbine, steam cycle, related systems)	$	122,077,000
Direct Costs Subtotal	$	498,574,000
Project Indirect	$	37,135,000
EPC Total Before Fee	$	535,709,000
EPC Fee	$	53,571,000
EPC Subtotal	$	589,280,000
Owner's Cost Components (Note 2)		
Owner's Services	$	46,000,000
Land	$	20,000,000
Electrical Interconnection	$	1,200,000
Owner's Cost Subtotal	$	67,200,000
Project Contingency	$	65,648,000
Total Capital Cost	**$**	**722,128,000**
	$/kW net	**7,221**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

23.3 O&M COST ESTIMATE

The O&M cost estimate incorporates the annual cost of the onsite O&M staff as well as contracted services for grounds keeping, mirror washing, water treatment, and computer maintenance. The O&M cost also incorporates the estimated annual water requirements, which will be purchased. The need for various consumables and replacement parts are also considered. Since the annual cost of consumables for the plant can be estimated, the entire O&M cost is captured as a fixed amount. The variable cost is considered to be $0.00/MWh.

Table 23-2 — Case 23 O&M Cost Estimate

Case 23 EIA – Non-Fuel O&M Costs – 2019 $s		
Concentrating Solar Power Tower		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**85.39 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials, utilities, and contracted services, and G&A costs. O&M Costs exclude property taxes and insurance.		
2. All costs tied to energy produced are covered in fixed cost.		

23.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Concentrating solar power plants do not produce regulated environmental emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 24. SOLAR PHOTOVOLTAIC, 150 MW_{AC}

24.1 CASE DESCRIPTION

This case is a nominal 150-MW_{AC} solar photovoltaic (PV) facility with single-axis tracking. With continued advances in technical efficiency and lower module price, solar PV cost has decreased significantly in the past decade. This case uses 195 MW_{DC} of 1,500-V monocrystalline PERC modules with independent row trackers that are placed in a north-south orientation with east-west tracking. The case also uses 150 MW_{AC} of central inverters, resulting in a DC/AC ratio of 1.3. The simplicity of solar PV projects is that there is no fuel or waste and limited moving parts; however, single-axis tracking systems require considerable land commitments due to a low ground coverage ratio intended to limit self-shading and create room for tracking rotation. Many tracking companies offer advanced backtracking software that help to optimize yield and ground coverage ratio, though this was not considered in this estimate.

Figure 24-1 — Solar Photovoltaic Project

Foothills Solar Project using single-axis tracking in Loveland, Colorado.

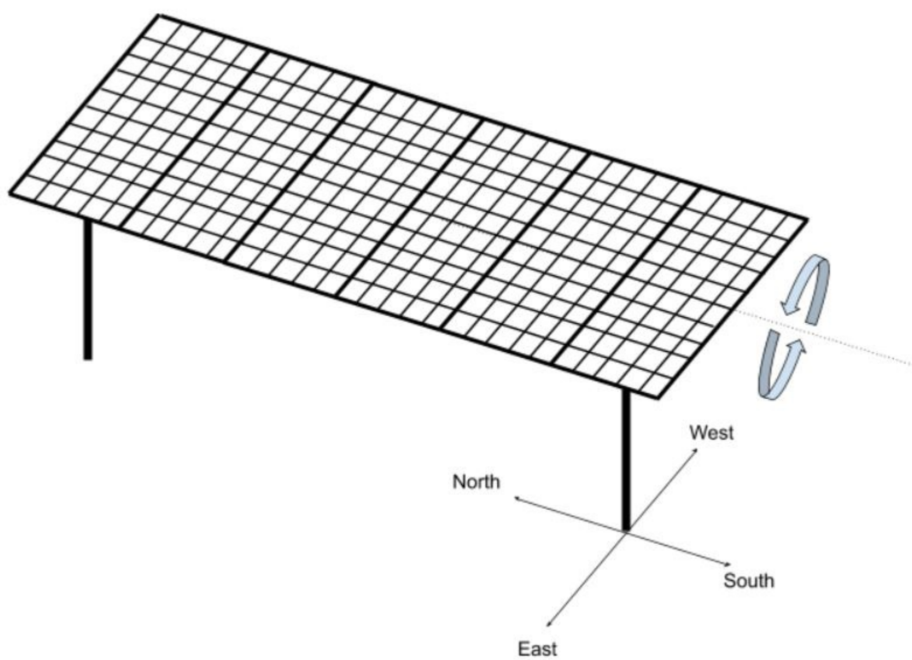
Source: American Public Power Association, *gray solar panel lot*, 2017. Digital Image.
Retrieved from: Unsplash.com, https://unsplash.com/photos/dCx2xFuPWks (accessed June 12, 2019).

24.1.1 Mechanical Equipment & Systems

PV refers to the conversion of light into electricity. Solar PV modules convert incident solar radiation into a potential difference within individual solar cells that produces DC electricity. The solar PV facility assumed for this study is comprised of 487,500 individual 400-watt, 1500-V monocrystalline solar modules with PERC architecture for increased efficiency. These modules are connected in series to each other in strings of 30 modules per string. The strings connect to each other in parallel to form large solar arrays, which make up the bulk of the facility. Arrays are often grouped together into distinct blocks throughout the plant with each block having a single designated inverter pad. Mechanical components of these arrays include the racking and solar tracking equipment. This estimate assumes the racking uses a driven pile foundation; however, depending on the site's geotechnical characteristics, ground screws and concrete foundations can also be used.

The tracking system's exact mechanics depend on the manufacturer. This system, and nearly all single-axis tracking systems currently being manufactured, use a north-south oriented tracking axis that is horizontally parallel with respect to the ground. This orientation allows the panels to track the sun as it crosses the sky east to west. One variation in tracking mechanics that can impact the overall price is linked versus unlinked row tracking. Linked row tracking connects multiple rows to a single tracker mechanism, thereby requiring them all to rotate at the same angle throughout the day. Unlinked row tracking allows individual rows to track the sun at different angles but require a solar tracker mechanism on each row. This case assumes an unlinked single-axis tracker technology.

Figure 24-2 — Single-Axis Tracking



24.1.2 Electrical & Control Systems

Each block within a PV is made up of identical components and functionality. Electrical components include:

- DC and AC wiring
- Combiner boxes
- Inverters
- Step-up transformers
- Control system
- Switchyard with electrical interconnection to the grid

As previously explained, modules are combined in series to form series strings. These strings are combined in parallel to form solar arrays. Arrays are then connected via combiner boxes to combine the current from each string of each array before feeding the DC power into an inverter. The number of arrays combined into each combiner box is dependent on the site layout, the current of each string, and the size of the combiner box. This estimate assumes one combiner box for every thirty strings. After DC cables from the combiner boxes are fed into the inverter, the inverter then converts the DC electricity from the combiner boxes into AC electricity. Inverters currently used in new projects are typically rated between 1,500 kW and 4000 kW. There are also two types of solar inverters: central and string. This system uses two 2500-kW central inverters with one 5.05-MW medium voltage transformer within each PV block.

A solar facility's nominal capacity is typically defined by the net AC capacity of the inverters across all blocks. In general, there will always be more installed DC capacity from the modules than AC capacity from the inverters. The ratio of DC to AC capacity (DC/AC ratio) is typically between 1.2 and 1.4; however, some projects increase the DC/AC ratio with the intention of harnessing the DC power that is clipped by the inverter's maximum capacity into battery storage energy. On the other side of the spectrum, some projects will decrease the DC/AC ratio to allow for additional reactive compensation. This estimate assumes a DC/AC ratio of 1.3.

24.1.3 Offsite Requirements

Solar PV facilities require no fuel and produce no waste. The offsite requirements are limited to an interconnection between the PV facility and the transmission system as well as water for the purpose of cleaning the solar modules. Additionally, cleaning is regionally dependent. In regions with significant rainfall and limited dust accumulation, cleaning is often unnecessary because it occurs naturally. In dust heavy and dry regions (which often have higher solar irradiance), cleaning occurs proportionally to the dust accumulation from once or twice a year up to bi-monthly and typically uses offsite water that is brought in on trucks. This analysis assumes two cleanings per year.

24.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1313/kW. Table 24-1 summarizes the cost components for this case. Solar prices have been dropping due to reductions in equipment costs as well as the required construction labor. As solar modeling software advances, projects are able to optimize layouts and ground coverage for lowest levelized cost of energy, thereby allowing for reduced civil expenditures on a per kilowatt basis. Solar modules that are arriving on the market have a net potential of 1500 V rather than the previous standard of 1000 V. This increased net potential allows for lower wiring losses, which increases the net energy yield and lower wiring material costs to reduce the capital cost. Additionally, strides have been made to make modules more efficient to increase their power rating and lighter in weight to allow for reduced transportation and installation cost. Electrical components have been dropping in price, especially the inverters. As solar development advances and matures, EPC contractors and developers have also been bearing less contingency and overhead, further reducing a solar project's overall price.

Table 24-1 — Case 24 Capital Cost Estimate

Case 24 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Solar PV w/ Single Axis Tracking** 150 MW_{AC}
DC / AC Ratio		1.3
Module Type		Crystalline
	Units	
Plant Characteristics		
Net Plant Capacity	MW_AC	150
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	5%
Project Contingency	% of Project Costs	5%
Owner's Services	% of Project Costs	4%
Estimated Land Requirement (acres) (Note 1)	$	400
Typical Project Timelines		
Development, Permitting, Engineering	months	12
Plant Construction Time	months	6
Total Lead Time Before COD	months	18
Operating Life	years	30

Case 24 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Solar PV w/ Single Axis Tracking 150 MW_{AC}	
DC / AC Ratio		1.3	
Module Type		Crystalline	
	Units		
Cost Components (Note 2)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		7,935,000
Mechanical – Racking, Tracking, & Module Installation	$	36,391,000	
Mechanical Subtotal	$		36,391,000
Electrical – Inverters	$	9,430,000	
Electrical – BOP and Miscellaneous	$	28,328,000	
Electrical – Transformer, Substation, & MV System	$	17,756,000	
Electrical – Backup Power, Control, & Data Acquisition	$	3,733,000	
Electrical Subtotal	$		59,247,000
Project Indirects	$		2,114,000
EPC Total Before Fee	$		105,687,000
EPC Fee	$		5,284,000
EPC Subtotal	$		110,971,000
Owner's Cost Components (Note 3)			
Owner's Services	$		4,439,000
Modules (Note 3)	$		72,150,000
Owner's Costs Subtotal	$		76,589,000
Project Contingency	$		9,378,000
Total Capital Cost	**$**		196,938,000
	$/kW net		**1,313**
Capital Cost Notes			
1. Land is typically leased and not considered in CAPEX. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.			
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.			
3. Modules purchased by Owner			

24.3 O&M COST ESTIMATE

Operations and maintenance costs associated with 150-MW_{AC}, single-axis tracking solar PV project have also been decreasing. There are five main factors to solar PV O&M: preventative maintenance, unscheduled maintenance, module cleaning, inverter maintenance reserve, and the land lease. As technological reliability increases and designs become more focused on decreasing O&M costs, preventative maintenance gets less costly and unscheduled maintenance occurs less frequently. Examples of O&M-focused designs are DC harnesses for optimal wiring configurations, wireless communication and control systems, and central inverter locations for ease of access. Cleaning is also typically less expensive for PV fields with trackers using independent rows because a single truck can clean two rows at a time instead of one. Additionally, inverter manufacturers have begun to offer extended warranties up to a 10-year period and at roughly the same cost as the assumed inverter reserve amount. Decreasing inverter prices also allows for a smaller inverter reserve to be set aside. The final annual expense is the land lease. Solar PV projects typically rent, rather than purchase, the land for the project; therefore, it is an operating expense and not a capital cost.

Table 24-2 — Case 24 O&M Cost Estimate

Case 24 EIA – Non-Fuel O&M Costs – 2019 $s		
Solar PV w/ Single Axis Tracking		
Fixed O&M – Plant ($/year) (Note 1)		
Preventative Maintenance	$/year	1,104,000
Module Cleaning (Note 2)	$/year	613,000
Unscheduled Maintenance	$/year	96,000
Inverter Maintenance Reserve	$/year	342,000
Land Lease (Note 3)	$/year	133,000
Subtotal Fixed O&M	$/year	2,288,000
$/kW-year	$/kW-year	**15.25 $/kW-yr**
Variable O&M ($/MWh)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M Costs exclude property taxes and insurance.		
2. Assume two module cleanings per year.		
3. Solar PV projects typically rent land rather than purchase it, this is considered to be a representative annual expense but varies across projects.		

24.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Solar PV does not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 25. SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MW_{AC}

25.1 CASE DESCRIPTION

This case is based on a nominal 150-MW_{AC} solar PV plant with 200 MWh of lithium-ion battery storage. Solar PV has increasingly been coupled with battery storage in recent years due to price reductions in solar PV and lithium-ion batteries. The factors driving cost reductions of solar PV projects are shared with systems coupled with battery storage: Modeling technology optimizes design and reduces civil costs per kW, higher power modules, lower priced inverters, and lower risk. Batteries can be either AC- or DC-coupled to the solar array. DC-coupled systems connect the battery directly to the solar array via DC wiring. This estimate assumes an AC-coupled system; this configuration is more prevalent in recent projects. AC-coupled systems offer higher efficiency when used in power AC applications, but they also have slightly lower efficiencies when charging the battery. The most common application for AC-coupled system is peak shaving, or energy arbitrage, where there is a limit on the power allowed into the grid and the peak of the solar generation is stored in a battery to be sold during the highest demand peaks for optimal profit.

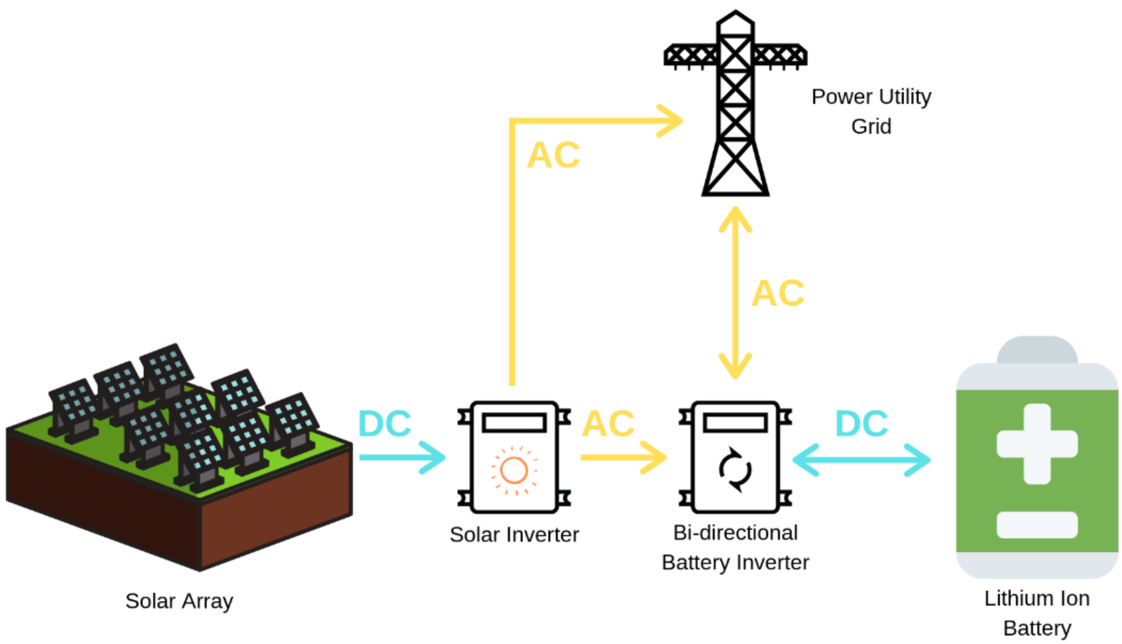
25.1.1 Mechanical Equipment & Systems

This case assumes a nominal 150-MW_{AC} solar PV plant with 200 MWh of lithium-ion battery storage. Batteries are typically sized by their output in kWh and not by their capacity in MW, which is defined by the AC capacity of the battery’s inverters. The 200-MWh battery system in this estimate is comprised of four hours of 50 MW output. The mechanical equipment for the solar portion is the same as a stand-alone solar PV facility: 400-watt solar modules, ground mounted racking with driven pile foundations, and independent single-axis tracking equipment. The mechanical equipment associated with the battery storage is the batteries themselves, the containers they are placed in, the fire suppression system, and the concrete foundations for the battery containers. This estimate assumes the use of 40 containers, each 40 feet in length and containing 5,000 kWh of battery storage. Smaller 20-feet containers are sometimes used depending on constraints with site availability and project size. Both the 20-foot and 40-foot containers are always installed with extra space inside to allow for annual installation of more batteries so that the entire container keeps a constant year-on-year net output despite battery degradation. There are more containers in a PV system with battery storage over a standalone BESS due to the increased project life of PV. The additional containers allow for more augmentation over the life of the PV project rather than the life of the battery storage.

25.1.2 Electrical & Control Systems

When incorporating AC-coupled battery storage into a solar PV site, there is no change in the electrical components of the solar array and solar inverters. The solar modules are connected in series with DC wiring into solar strings. The solar strings are connected in parallel to combiner boxes that output the current into the solar inverters. The output of the solar inverter then enters a switchgear that feeds the AC current into either the grid or the battery inverter. It is also important to note that battery storage inverters are different from solar inverters in that they are typically bi-direction inverters that can alternate between inverting AC to DC and inverting DC to AC. Battery storage inverters also allow the batteries to be charged by either the solar array or the grid. This facility uses 150 MW of solar inverters plus 50 MW of battery inverters. Battery inverters are significantly more expensive than solar inverters.

Figure 25-1 — AC Coupled Solar PV and Battery Storage



Adapted from Clean Energy Reviews,
https://www.cleanenergyreviews.info/blog/ac-coupling-vs-dc-coupling-solar-battery-storage (accessed June 12, 2019).

Whether power is being used from the battery storage or the solar array, it passes through a switchyard that contains the circuit breaker, step-up transformer, and electrical interconnection with the grid.

25.1.3 Offsite Requirements

Solar PV and battery storage facilities require no fuel and produce no waste. The offsite requirements are limited to an interconnection between the facility and the transmission system as well as water for the purpose of cleaning the solar modules. Cleaning is regionally dependent. In regions with significant rainfall and limited dust accumulation, cleaning is often unnecessary and occurs naturally. In dust heavy and dry regions, cleaning typically occurs once or twice a year and uses offsite water that is brought in on trucks. This analysis assumes two cleanings per year.

25.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1755/kW. Table 25-1 summarizes the cost components for this case.

Table 25-1 — Case 25 Capital Cost Estimate

Case 25 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Solar PV w/ Single Axis Tracking + Battery Storage	
Battery Configuration		AC Coupled	
DC / AC Ratio		1.3	
Module Type		Crystalline	
Battery Type		Lithium-ion	
	Units		
Plant Characteristics			
Net Solar Capacity	MW_AC	150	
Net Battery Capacity	MW_AC	50	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	5%	
Project Contingency	% of Project Costs	5%	
Owner's Services	% of Project Costs	4%	
Estimated Land Requirement (acres) Note 1	$	401	
Typical Project Timelines			
Development, Permitting, Engineering	months	12	
Plant Construction Time	months	6	
Total Lead Time Before COD	months	18	
Operating Life	years	30	
Cost Components (Note 2)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		17,596,000
Mechanical – Racking, Tracking, & Module Installation	$	36,391,000	
Mechanical Subtotal	$		36,391,000
Electrical – Batteries	$	40,037,000	
Electrical – Inverters	$	14,459,000	
Electrical – BOP and Miscellaneous	$	28,453,000	
Electrical – Transformer, Substation, & MV System	$	18,647,000	
Electrical – Backup Power, Control, & Data Acquisition	$	3,755,000	
Electrical Subtotal	$		105,350,000
Project Indirects	$		4,202,000
EPC Total Before Fee	$		163,539,000
EPC Fee	$		8,177,000
EPC Subtotal	$		171,716,000
Owner's Cost Components (Note 3)			
Owner's Services	$		6,869,000

Case 25 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Solar PV w/ Single Axis Tracking + Battery Storage**
Battery Configuration		AC Coupled
DC / AC Ratio		1.3
Module Type		Crystalline
Battery Type		Lithium-ion
	Units	
Modules (Note 3)	$	72,150,000
Owner's Cost Subtotal	$	79,019,000
Project Contingency	$	12,537,000
Total Capital Cost	**$**	263,272,000
	$/kW net	**1,755**
Capital Cost Notes		
1. Land is typically leased and not considered in CAPEX. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.		
3. Modules purchased directly by owner.		

25.3 O&M COST ESTIMATE

For this case, Sargent & Lundy grouped the O&M costs into the following categories: preventative maintenance, unscheduled maintenance, module cleaning, inverter maintenance reserve, battery maintenance reserve, and the land lease. Descriptions of all the factors except the battery maintenance reserve can be found in Section 24.3. The typical lifetime of a battery is 3000 cycles, which yields a lifetime of roughly 10 years (based on approximately one cycle per day). Battery systems typically account for degradation and a 10-year battery lifetime by leaving physical space within the BESS containers for additional batteries to be installed to augment the system each year. The battery reserve in this case is higher than standalone battery storage because it accounts for battery augmentation as well as additional battery replacements every 10 years to allow for a 30-year system life.

Table 25-2 — Case 25 O&M Cost Estimate

Case 25 EIA – Non-Fuel O&M Costs – 2019 $s		
Solar PV w/ Single Axis Tracking + Battery Storage		
Fixed O&M – Plant (Note 1)		
Preventative Maintenance	$/year	1,545,000
Module Cleaning (Note 2)	$/year	613,000
Unscheduled Maintenance	$/year	115,000
Inverter Maintenance Reserve	$/year	455,000
Battery Maintenance Reserve	$/year	1,963,000
Land Lease (Note 3)	$/year	134,000
Subtotal Fixed O&M	$/year	4,825,000
$/kW-year	$/kW-year	**32.17 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M Costs exclude property taxes and insurance.		
2. Assume two module cleanings per year.		
3. Solar PV projects typically rent land rather than purchase it, this is considered to be a representative annual expense but varies across projects.		

25.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Neither solar PV nor battery storage produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

Appendix A. Location-Based Adjustment Factors

Location-Based Adjustment Factors

Capital Cost Study

Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies

Prepared by
Sargent & Lundy

Prepared for
U.S. Energy Information Administration

FINAL

Contract No. 89303019CEI00022
Project No. 13651-005

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Table 1 1 — Location Adjustment for Non-New Source Performance Standard Compliant Ultra-Supercritical Coal (NSPS for NOX, Sox, PM, Hg)
(2019 Dollars)
Case Configuration: 650 MW Net

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	3,676	0.97	(128)	3549
Arizona	Phoenix	3,676	1.05	199	3875
Arkansas	Little Rock	3,676	0.96	(133)	3543
California	Bakersfield	3,676	1.26	973	4649
California	Los Angeles	3,676	1.27	989	4665
California	Modesto (instead of Redding)	3,676	1.28	1,017	4694
California	Sacramento	3,676	1.29	1,076	4752
California	San Francisco	3,676	1.37	1,367	5043
Colorado	Denver	3,676	1.03	100	3776
Connecticut	Hartford	3,676	1.24	877	4554
Delaware	Dover	3,676	1.22	801	4477
District of Columbia	Washington	3,676	1.08	307	3983
Florida	Tallahassee	3,676	0.95	(194)	3483
Florida	Tampa	3,676	0.97	(127)	3549
Georgia	Atlanta	3,676	0.99	(46)	3630
Idaho	Boise	3,676	1.03	105	3781
Illinois	Chicago	3,676	1.28	1,018	4694
Illinois	Joliet	3,676	1.24	869	4545
Indiana	Indianapolis	3,676	1.02	74	3750
Iowa	Davenport	3,676	1.05	173	3850
Iowa	Waterloo	3,676	0.97	(97)	3579
Kansas	Wichita	3,676	0.98	(85)	3592
Kentucky	Louisville	3,676	1.01	26	3702
Louisiana	New Orleans	3,676	0.97	(104)	3572
Maine	Portland	3,676	1.03	114	3790
Maryland	Baltimore	3,676	1.02	86	3762
Massachusetts	Boston	3,676	1.29	1,050	4726
Michigan	Detroit	3,676	1.12	459	4135
Michigan	Grand Rapids	3,676	1.05	168	3844
Minnesota	Saint Paul	3,676	1.11	411	4087
Mississippi	Jackson	3,676	0.95	(186)	3490
Missouri	St. Louis	3,676	1.13	461	4137
Missouri	Kansas City	3,676	1.08	297	3974
Montana	Great Falls	3,676	0.97	(104)	3572
Nebraska	Omaha	3,676	0.98	(78)	3599
New Hampshire	Concord	3,676	1.14	510	4186
New Jersey	Newark	3,676	1.24	881	4557
New Mexico	Albuquerque	3,676	0.99	(47)	3629
New York	New York	3,676	1.57	2,109	5785
New York	Syracuse	3,676	1.13	487	4163
Nevada	Las Vegas	3,676	1.15	556	4233
North Carolina	Charlotte	3,676	0.96	(144)	3532
North Dakota	Bismarck	3,676	1.04	133	3810
Oklahoma	Oklahoma City	3,676	1.01	30	3707
Oklahoma	Tulsa	3,676	0.93	(261)	3415
Ohio	Cincinnati	3,676	0.93	(262)	3414
Oregon	Portland	3,676	1.16	584	4261
Pennsylvania	Philadelphia	3,676	1.30	1,092	4769
Pennsylvania	Wilkes-Barre	3,676	1.15	561	4238
Rhode Island	Providence	3,676	1.21	781	4457
South Carolina	Charleston	3,676	0.96	(159)	3518
South Carolina	Spartanburg (Asheville, NC)	3,676	0.97	(116)	3561
South Dakota	Rapid City	3,676	0.98	(73)	3603
Tennessee	Knoxville (Nashville)	3,676	0.97	(104)	3573
Texas	Houston	3,676	0.93	(260)	3416
Utah	Salt Lake City	3,676	0.98	(60)	3617
Vermont	Burlington	3,676	1.05	167	3843
Virginia	Alexandria	3,676	1.08	280	3956
Virginia	Lynchburg	3,676	1.02	70	3746
Washington	Seattle	3,676	1.14	505	4182
Washington	Spokane	3,676	1.06	210	3886
West Virginia	Charleston	3,676	1.04	162	3839
Wisconsin	Green Bay	3,676	1.06	209	3886
Wyoming	Cheyenne	3,676	0.99	(20)	3656

Table 1 2 — Location Adjustment for New Source Performance Standard Compliant Ultra-Supercritical Coal (with 30% CCS or Other Compliance Technology) (2019 Dollars)

Case Configuration: 650 MW Net

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	4,558	0.97	(155)	4,403
Arizona	Phoenix	4,558	1.05	250	4,808
Arkansas	Little Rock	4,558	0.97	(129)	4,429
California	Bakersfield	4,558	1.24	1,114	5,672
California	Los Angeles	4,558	1.25	1,132	5,690
California	Modesto (instead of Redding)	4,558	1.26	1,162	5,721
California	Sacramento	4,558	1.27	1,227	5,785
California	San Francisco	4,558	1.34	1,547	6,105
Colorado	Denver	4,558	1.03	139	4,697
Connecticut	Hartford	4,558	1.22	1,000	5,558
Delaware	Dover	4,558	1.20	905	5,463
District of Columbia	Washington	4,558	1.08	371	4,929
Florida	Tallahassee	4,558	0.95	(209)	4,349
Florida	Tampa	4,558	0.97	(135)	4,423
Georgia	Atlanta	4,558	0.99	(42)	4,516
Idaho	Boise	4,558	1.03	120	4,678
Illinois	Chicago	4,558	1.25	1,118	5,676
Illinois	Joliet	4,558	1.21	954	5,513
Indiana	Indianapolis	4,558	1.02	88	4,646
Iowa	Davenport	4,558	1.04	190	4,748
Iowa	Waterloo	4,558	0.98	(107)	4,451
Kansas	Wichita	4,558	0.98	(93)	4,465
Kentucky	Louisville	4,558	1.01	35	4,593
Louisiana	New Orleans	4,558	0.98	(101)	4,458
Maine	Portland	4,558	1.03	128	4,686
Maryland	Baltimore	4,558	1.02	96	4,654
Massachusetts	Boston	4,558	1.26	1,191	5,749
Michigan	Detroit	4,558	1.11	504	5,062
Michigan	Grand Rapids	4,558	1.04	184	4,742
Minnesota	Saint Paul	4,558	1.10	444	5,002
Mississippi	Jackson	4,558	0.96	(202)	4,356
Missouri	St. Louis	4,558	1.11	523	5,081
Missouri	Kansas City	4,558	1.07	327	4,885
Montana	Great Falls	4,558	0.97	(116)	4,442
Nebraska	Omaha	4,558	0.98	(85)	4,473
New Hampshire	Concord	4,558	1.13	603	5,162
New Jersey	Newark	4,558	1.21	970	5,528
New Mexico	Albuquerque	4,558	0.99	(37)	4,521
New York	New York	4,558	1.52	2,351	6,910
New York	Syracuse	4,558	1.12	567	5,125
Nevada	Las Vegas	4,558	1.14	623	5,182
North Carolina	Charlotte	4,558	0.97	(158)	4,400
North Dakota	Bismarck	4,558	1.03	139	4,697
Oklahoma	Oklahoma City	4,558	1.01	32	4,590
Oklahoma	Tulsa	4,558	0.94	(288)	4,270
Ohio	Cincinnati	4,558	0.94	(289)	4,269
Oregon	Portland	4,558	1.15	687	5,245
Pennsylvania	Philadelphia	4,558	1.27	1,234	5,793
Pennsylvania	Wilkes-Barre	4,558	1.14	649	5,208
Rhode Island	Providence	4,558	1.20	896	5,455
South Carolina	Charleston	4,558	0.97	(144)	4,414
South Carolina	Spartanburg (Asheville, NC)	4,558	0.97	(119)	4,439
South Dakota	Rapid City	4,558	0.98	(88)	4,470
Tennessee	Knoxville (Nashville)	4,558	0.98	(100)	4,458
Texas	Houston	4,558	0.94	(285)	4,273
Utah	Salt Lake City	4,558	0.99	(52)	4,506
Vermont	Burlington	4,558	1.05	210	4,768
Virginia	Alexandria	4,558	1.07	341	4,899
Virginia	Lynchburg	4,558	1.02	108	4,666
Washington	Seattle	4,558	1.12	569	5,127
Washington	Spokane	4,558	1.05	236	4,795
West Virginia	Charleston	4,558	1.04	178	4,736
Wisconsin	Green Bay	4,558	1.05	221	4,779
Wyoming	Cheyenne	4,558	0.99	(25)	4,533

Table 1 3 — Location Adjustment for Ultra-Supercritical Coal (with 90% CCS)
(2019 Dollars)
Case Configuration: 650 MW Net

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	5,876	0.98	(126)	5750
Arizona	Phoenix	5,876	1.04	232	6108
Arkansas	Little Rock	5,876	0.98	(99)	5777
California	Bakersfield	5,876	1.22	1,278	7153
California	Los Angeles	5,876	1.22	1,300	7176
California	Modesto (instead of Redding)	5,876	1.23	1,333	7209
California	Sacramento	5,876	1.24	1,408	7284
California	San Francisco	5,876	1.30	1,778	7654
Colorado	Denver	5,876	1.02	99	5974
Connecticut	Hartford	5,876	1.19	1,114	6990
Delaware	Dover	5,876	1.17	972	6848
District of Columbia	Washington	5,876	1.06	381	6257
Florida	Tallahassee	5,876	0.96	(235)	5640
Florida	Tampa	5,876	0.98	(143)	5733
Georgia	Atlanta	5,876	1.00	(21)	5855
Idaho	Boise	5,876	1.03	155	6031
Illinois	Chicago	5,876	1.22	1,310	7186
Illinois	Joliet	5,876	1.19	1,118	6994
Indiana	Indianapolis	5,876	1.02	126	6001
Iowa	Davenport	5,876	1.04	221	6097
Iowa	Waterloo	5,876	0.98	(125)	5751
Kansas	Wichita	5,876	0.98	(111)	5765
Kentucky	Louisville	5,876	1.01	64	5939
Louisiana	New Orleans	5,876	0.99	(74)	5802
Maine	Portland	5,876	1.03	157	6033
Maryland	Baltimore	5,876	1.02	118	5993
Massachusetts	Boston	5,876	1.23	1,341	7216
Michigan	Detroit	5,876	1.10	590	6466
Michigan	Grand Rapids	5,876	1.04	214	6090
Minnesota	Saint Paul	5,876	1.08	497	6372
Mississippi	Jackson	5,876	0.96	(230)	5645
Missouri	St. Louis	5,876	1.11	667	6543
Missouri	Kansas City	5,876	1.07	383	6259
Montana	Great Falls	5,876	0.98	(142)	5734
Nebraska	Omaha	5,876	0.98	(99)	5777
New Hampshire	Concord	5,876	1.12	682	6558
New Jersey	Newark	5,876	1.20	1,146	7022
New Mexico	Albuquerque	5,876	1.00	3	5879
New York	New York	5,876	1.46	2,675	8551
New York	Syracuse	5,876	1.10	602	6477
Nevada	Las Vegas	5,876	1.13	772	6648
North Carolina	Charlotte	5,876	0.97	(186)	5690
North Dakota	Bismarck	5,876	1.02	137	6013
Oklahoma	Oklahoma City	5,876	1.01	32	5908
Oklahoma	Tulsa	5,876	0.94	(341)	5535
Ohio	Cincinnati	5,876	0.94	(342)	5534
Oregon	Portland	5,876	1.13	782	6658
Pennsylvania	Philadelphia	5,876	1.24	1,382	7258
Pennsylvania	Wilkes-Barre	5,876	1.12	700	6576
Rhode Island	Providence	5,876	1.17	1,005	6881
South Carolina	Charleston	5,876	0.99	(72)	5804
South Carolina	Spartanburg (Asheville, NC)	5,876	0.98	(113)	5763
South Dakota	Rapid City	5,876	0.98	(128)	5748
Tennessee	Knoxville (Nashville)	5,876	0.99	(71)	5804
Texas	Houston	5,876	0.94	(331)	5545
Utah	Salt Lake City	5,876	1.00	(18)	5858
Vermont	Burlington	5,876	1.06	334	6209
Virginia	Alexandria	5,876	1.06	346	6222
Virginia	Lynchburg	5,876	1.01	71	5947
Washington	Seattle	5,876	1.12	713	6589
Washington	Spokane	5,876	1.05	298	6173
West Virginia	Charleston	5,876	1.04	206	6082
Wisconsin	Green Bay	5,876	1.04	229	6105
Wyoming	Cheyenne	5,876	0.99	(40)	5836

Table 1 4 — Location Adjustment for Internal Combustion Engines (Natural Gas or Oil-fired Diesel)
(2019 Dollars)
Case Configuration: 20 MW (4x 5.6 MW)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,810	0.97	(48)	1,762
Arizona	Phoenix	1,810	0.98	(32)	1,778
Arkansas	Little Rock	1,810	0.98	(32)	1,777
California	Bakersfield	1,810	1.16	292	2,102
California	Los Angeles	1,810	1.17	303	2,112
California	Modesto (instead of Redding)	1,810	1.16	292	2,102
California	Sacramento	1,810	1.17	314	2,124
California	San Francisco	1,810	1.26	465	2,275
Colorado	Denver	1,810	0.97	(57)	1,752
Connecticut	Hartford	1,810	1.14	252	2,062
Delaware	Dover	1,810	1.10	176	1,985
District of Columbia	Washington	1,810	1.02	42	1,852
Florida	Tallahassee	1,810	0.96	(80)	1,730
Florida	Tampa	1,810	0.97	(61)	1,749
Georgia	Atlanta	1,810	0.99	(17)	1,793
Idaho	Boise	1,810	1.02	36	1,846
Illinois	Chicago	1,810	1.21	382	2,191
Illinois	Joliet	1,810	1.18	320	2,129
Indiana	Indianapolis	1,810	1.02	37	1,846
Iowa	Davenport	1,810	1.04	66	1,876
Iowa	Waterloo	1,810	0.98	(33)	1,777
Kansas	Wichita	1,810	0.98	(27)	1,782
Kentucky	Louisville	1,810	1.01	13	1,823
Louisiana	New Orleans	1,810	0.98	(27)	1,782
Maine	Portland	1,810	1.01	27	1,836
Maryland	Baltimore	1,810	1.02	36	1,845
Massachusetts	Boston	1,810	1.18	320	2,129
Michigan	Detroit	1,810	1.09	161	1,971
Michigan	Grand Rapids	1,810	1.02	42	1,852
Minnesota	Saint Paul	1,810	1.08	148	1,958
Mississippi	Jackson	1,810	0.96	(78)	1,731
Missouri	St. Louis	1,810	1.12	210	2,019
Missouri	Kansas City	1,810	1.07	118	1,928
Montana	Great Falls	1,810	0.98	(39)	1,770
Nebraska	Omaha	1,810	0.99	(24)	1,785
New Hampshire	Concord	1,810	1.06	117	1,927
New Jersey	Newark	1,810	1.19	342	2,152
New Mexico	Albuquerque	1,810	1.00	1	1,811
New York	New York	1,810	1.37	673	2,483
New York	Syracuse	1,810	1.05	96	1,906
Nevada	Las Vegas	1,810	1.12	224	2,034
North Carolina	Charlotte	1,810	0.97	(56)	1,754
North Dakota	Bismarck	1,810	1.00	8	1,818
Oklahoma	Oklahoma City	1,810	1.00	2	1,811
Oklahoma	Tulsa	1,810	0.94	(101)	1,709
Ohio	Cincinnati	1,810	0.94	(101)	1,709
Oregon	Portland	1,810	1.09	157	1,966
Pennsylvania	Philadelphia	1,810	1.18	326	2,136
Pennsylvania	Wilkes-Barre	1,810	1.06	108	1,918
Rhode Island	Providence	1,810	1.12	217	2,027
South Carolina	Charleston	1,810	0.99	(15)	1,795
South Carolina	Spartanburg (Asheville, NC)	1,810	0.98	(39)	1,770
South Dakota	Rapid City	1,810	0.98	(40)	1,770
Tennessee	Knoxville (Nashville)	1,810	0.99	(15)	1,794
Texas	Houston	1,810	0.94	(108)	1,702
Utah	Salt Lake City	1,810	1.00	0	1,809
Vermont	Burlington	1,810	1.05	94	1,904
Virginia	Alexandria	1,810	1.02	35	1,844
Virginia	Lynchburg	1,810	0.97	(57)	1,753
Washington	Seattle	1,810	1.13	231	2,041
Washington	Spokane	1,810	1.04	65	1,874
West Virginia	Charleston	1,810	1.03	55	1,864
Wisconsin	Green Bay	1,810	1.03	55	1,865
Wyoming	Cheyenne	1,810	0.99	(18)	1,791

Table 1 5 — Location Adjustment for Combined-Cycle Oil/Natural Gas Turbine
(2019 Dollars)
Case Configuration: 100 MW, 2 x LM6000

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,175	0.96	(53)	1,122
Arizona	Phoenix	1,175	0.98	(26)	1,149
Arkansas	Little Rock	1,175	0.96	(49)	1,126
California	Bakersfield	1,175	1.16	192	1,367
California	Los Angeles	1,175	1.18	206	1,381
California	Modesto (instead of Redding)	1,175	1.17	199	1,374
California	Sacramento	1,175	1.19	218	1,393
California	San Francisco	1,175	1.31	359	1,534
Colorado	Denver	1,175	0.97	(39)	1,136
Connecticut	Hartford	1,175	1.15	172	1,347
Delaware	Dover	1,175	1.13	157	1,331
District of Columbia	Washington	1,175	1.02	28	1,203
Florida	Tallahassee	1,175	0.94	(67)	1,107
Florida	Tampa	1,175	0.96	(52)	1,123
Georgia	Atlanta	1,175	0.98	(29)	1,145
Idaho	Boise	1,175	1.01	14	1,189
Illinois	Chicago	1,175	1.23	270	1,445
Illinois	Joliet	1,175	1.20	234	1,409
Indiana	Indianapolis	1,175	1.01	9	1,184
Iowa	Davenport	1,175	1.03	39	1,214
Iowa	Waterloo	1,175	0.96	(41)	1,133
Kansas	Wichita	1,175	0.97	(38)	1,137
Kentucky	Louisville	1,175	0.99	(6)	1,168
Louisiana	New Orleans	1,175	0.96	(45)	1,130
Maine	Portland	1,175	1.00	6	1,181
Maryland	Baltimore	1,175	1.02	19	1,194
Massachusetts	Boston	1,175	1.20	229	1,404
Michigan	Detroit	1,175	1.11	128	1,303
Michigan	Grand Rapids	1,175	1.03	35	1,210
Minnesota	Saint Paul	1,175	1.09	106	1,281
Mississippi	Jackson	1,175	0.94	(65)	1,109
Missouri	St. Louis	1,175	1.11	129	1,304
Missouri	Kansas City	1,175	1.07	82	1,256
Montana	Great Falls	1,175	0.96	(42)	1,133
Nebraska	Omaha	1,175	0.97	(32)	1,142
New Hampshire	Concord	1,175	1.05	59	1,233
New Jersey	Newark	1,175	1.22	253	1,428
New Mexico	Albuquerque	1,175	0.98	(27)	1,148
New York	New York	1,175	1.43	500	1,675
New York	Syracuse	1,175	1.06	69	1,244
Nevada	Las Vegas	1,175	1.12	146	1,321
North Carolina	Charlotte	1,175	0.96	(49)	1,126
North Dakota	Bismarck	1,175	1.02	22	1,196
Oklahoma	Oklahoma City	1,175	1.00	(1)	1,173
Oklahoma	Tulsa	1,175	0.93	(82)	1,092
Ohio	Cincinnati	1,175	0.93	(83)	1,092
Oregon	Portland	1,175	1.08	96	1,271
Pennsylvania	Philadelphia	1,175	1.21	251	1,426
Pennsylvania	Wilkes-Barre	1,175	1.06	73	1,248
Rhode Island	Providence	1,175	1.12	138	1,313
South Carolina	Charleston	1,175	0.95	(55)	1,120
South Carolina	Spartanburg (Asheville, NC)	1,175	0.96	(47)	1,128
South Dakota	Rapid City	1,175	0.97	(33)	1,142
Tennessee	Knoxville (Nashville)	1,175	0.97	(31)	1,144
Texas	Houston	1,175	0.93	(84)	1,091
Utah	Salt Lake City	1,175	0.97	(34)	1,141
Vermont	Burlington	1,175	1.02	27	1,202
Virginia	Alexandria	1,175	1.02	21	1,195
Virginia	Lynchburg	1,175	0.96	(52)	1,123
Washington	Seattle	1,175	1.14	160	1,334
Washington	Spokane	1,175	1.04	45	1,220
West Virginia	Charleston	1,175	1.04	43	1,218
Wisconsin	Green Bay	1,175	1.04	44	1,219
Wyoming	Cheyenne	1,175	0.99	(14)	1,161

Table 1 6 — Location Adjustment for Combined-Cycle Oil/Natural Gas Turbine
(2019 Dollars)
Case Configuration: 1 x 240 MW, F-Class

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	713	0.95	(33)	680
Arizona	Phoenix	713	0.98	(16)	696
Arkansas	Little Rock	713	0.96	(30)	683
California	Bakersfield	713	1.17	122	834
California	Los Angeles	713	1.18	130	843
California	Modesto (instead of Redding)	713	1.18	126	839
California	Sacramento	713	1.19	138	851
California	San Francisco	713	1.32	227	940
Colorado	Denver	713	0.97	(25)	688
Connecticut	Hartford	713	1.15	109	821
Delaware	Dover	713	1.14	99	811
District of Columbia	Washington	713	1.03	18	731
Florida	Tallahassee	713	0.94	(42)	670
Florida	Tampa	713	0.95	(33)	680
Georgia	Atlanta	713	0.97	(18)	695
Idaho	Boise	713	1.01	9	722
Illinois	Chicago	713	1.24	170	883
Illinois	Joliet	713	1.21	147	860
Indiana	Indianapolis	713	1.01	6	719
Iowa	Davenport	713	1.03	25	738
Iowa	Waterloo	713	0.96	(26)	687
Kansas	Wichita	713	0.97	(24)	689
Kentucky	Louisville	713	0.99	(4)	709
Louisiana	New Orleans	713	0.96	(28)	685
Maine	Portland	713	1.01	4	717
Maryland	Baltimore	713	1.02	12	725
Massachusetts	Boston	713	1.20	145	857
Michigan	Detroit	713	1.11	81	794
Michigan	Grand Rapids	713	1.03	22	735
Minnesota	Saint Paul	713	1.09	66	779
Mississippi	Jackson	713	0.94	(41)	672
Missouri	St. Louis	713	1.12	82	795
Missouri	Kansas City	713	1.07	51	764
Montana	Great Falls	713	0.96	(27)	686
Nebraska	Omaha	713	0.97	(20)	692
New Hampshire	Concord	713	1.05	37	750
New Jersey	Newark	713	1.22	160	873
New Mexico	Albuquerque	713	0.98	(16)	696
New York	New York	713	1.44	315	1,028
New York	Syracuse	713	1.06	43	756
Nevada	Las Vegas	713	1.13	92	805
North Carolina	Charlotte	713	0.96	(31)	682
North Dakota	Bismarck	713	1.02	13	726
Oklahoma	Oklahoma City	713	1.00	(1)	712
Oklahoma	Tulsa	713	0.93	(52)	661
Ohio	Cincinnati	713	0.93	(52)	661
Oregon	Portland	713	1.09	61	774
Pennsylvania	Philadelphia	713	1.22	159	871
Pennsylvania	Wilkes-Barre	713	1.06	46	759
Rhode Island	Providence	713	1.12	88	800
South Carolina	Charleston	713	0.95	(33)	679
South Carolina	Spartanburg (Asheville, NC)	713	0.96	(29)	683
South Dakota	Rapid City	713	0.97	(21)	692
Tennessee	Knoxville (Nashville)	713	0.97	(19)	694
Texas	Houston	713	0.93	(53)	660
Utah	Salt Lake City	713	0.97	(21)	692
Vermont	Burlington	713	1.03	18	731
Virginia	Alexandria	713	1.02	13	726
Virginia	Lynchburg	713	0.95	(33)	680
Washington	Seattle	713	1.14	101	814
Washington	Spokane	713	1.04	29	742
West Virginia	Charleston	713	1.04	27	740
Wisconsin	Green Bay	713	1.04	27	740
Wyoming	Cheyenne	713	0.99	(9)	704

**Table 1 7 — Location Adjustment for Combined-Cycle Oil/Natural Gas Turbine
(2019 Dollars)
Case Configuration: 1100 MW, H-Class, 2x2x1**

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	958	0.95	(51)	907
Arizona	Phoenix	958	1.05	50	1,008
Arkansas	Little Rock	958	0.95	(49)	910
California	Bakersfield	958	1.28	270	1,229
California	Los Angeles	958	1.30	285	1,243
California	Modesto (instead of Redding)	958	1.29	278	1,236
California	Sacramento	958	1.31	298	1,256
California	San Francisco	958	1.46	442	1,401
Colorado	Denver	958	1.04	36	994
Connecticut	Hartford	958	1.26	252	1,210
Delaware	Dover	958	1.25	238	1,196
District of Columbia	Washington	958	1.11	104	1,063
Florida	Tallahassee	958	0.93	(64)	894
Florida	Tampa	958	0.95	(50)	908
Georgia	Atlanta	958	0.97	(29)	929
Idaho	Boise	958	1.01	13	971
Illinois	Chicago	958	1.27	257	1,216
Illinois	Joliet	958	1.23	223	1,181
Indiana	Indianapolis	958	1.01	8	966
Iowa	Davenport	958	1.04	38	996
Iowa	Waterloo	958	0.96	(40)	919
Kansas	Wichita	958	0.96	(36)	922
Kentucky	Louisville	958	0.99	(7)	951
Louisiana	New Orleans	958	0.95	(45)	913
Maine	Portland	958	1.01	5	963
Maryland	Baltimore	958	1.02	18	977
Massachusetts	Boston	958	1.32	310	1,269
Michigan	Detroit	958	1.13	122	1,081
Michigan	Grand Rapids	958	1.03	33	992
Minnesota	Saint Paul	958	1.11	102	1,061
Mississippi	Jackson	958	0.93	(62)	896
Missouri	St. Louis	958	1.13	120	1,079
Missouri	Kansas City	958	1.08	78	1,036
Montana	Great Falls	958	0.96	(40)	919
Nebraska	Omaha	958	0.97	(31)	927
New Hampshire	Concord	958	1.14	134	1,092
New Jersey	Newark	958	1.25	241	1,200
New Mexico	Albuquerque	958	0.97	(28)	931
New York	New York	958	1.61	589	1,548
New York	Syracuse	958	1.15	146	1,105
Nevada	Las Vegas	958	1.14	137	1,095
North Carolina	Charlotte	958	0.95	(47)	912
North Dakota	Bismarck	958	1.02	22	980
Oklahoma	Oklahoma City	958	1.00	(1)	957
Oklahoma	Tulsa	958	0.92	(78)	880
Ohio	Cincinnati	958	0.92	(79)	880
Oregon	Portland	958	1.09	90	1,048
Pennsylvania	Philadelphia	958	1.35	333	1,292
Pennsylvania	Wilkes-Barre	958	1.16	150	1,109
Rhode Island	Providence	958	1.23	217	1,175
South Carolina	Charleston	958	0.94	(57)	901
South Carolina	Spartanburg (Asheville, NC)	958	0.95	(46)	912
South Dakota	Rapid City	958	0.97	(30)	929
Tennessee	Knoxville (Nashville)	958	0.97	(32)	927
Texas	Houston	958	0.92	(80)	878
Utah	Salt Lake City	958	0.96	(35)	924
Vermont	Burlington	958	1.02	21	979
Virginia	Alexandria	958	1.10	96	1,055
Virginia	Lynchburg	958	1.02	22	981
Washington	Seattle	958	1.16	150	1,108
Washington	Spokane	958	1.04	42	1,001
West Virginia	Charleston	958	1.04	41	999
Wisconsin	Green Bay	958	1.05	43	1,002
Wyoming	Cheyenne	958	0.99	(13)	945

Table 1 8 — Location Adjustment for Combined-Cycle Single Shaft
(2019 Dollars)
Case Configuration: 430 MW, H-Class 1x1x1

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,084	0.96	(49)	1,035
Arizona	Phoenix	1,084	1.10	114	1,197
Arkansas	Little Rock	1,084	0.96	(47)	1,036
California	Bakersfield	1,084	1.30	324	1,407
California	Los Angeles	1,084	1.31	337	1,421
California	Modesto (instead of Redding)	1,084	1.31	331	1,415
California	Sacramento	1,084	1.32	350	1,434
California	San Francisco	1,084	1.45	489	1,573
Colorado	Denver	1,084	1.09	100	1,184
Connecticut	Hartford	1,084	1.28	308	1,391
Delaware	Dover	1,084	1.27	296	1,380
District of Columbia	Washington	1,084	1.15	166	1,249
Florida	Tallahassee	1,084	0.94	(60)	1,024
Florida	Tampa	1,084	0.96	(47)	1,037
Georgia	Atlanta	1,084	0.97	(28)	1,056
Idaho	Boise	1,084	1.01	11	1,095
Illinois	Chicago	1,084	1.22	238	1,322
Illinois	Joliet	1,084	1.19	206	1,290
Indiana	Indianapolis	1,084	1.01	6	1,090
Iowa	Davenport	1,084	1.03	35	1,119
Iowa	Waterloo	1,084	0.97	(37)	1,047
Kansas	Wichita	1,084	0.97	(34)	1,050
Kentucky	Louisville	1,084	0.99	(8)	1,076
Louisiana	New Orleans	1,084	0.96	(43)	1,040
Maine	Portland	1,084	1.00	4	1,088
Maryland	Baltimore	1,084	1.02	17	1,100
Massachusetts	Boston	1,084	1.34	364	1,447
Michigan	Detroit	1,084	1.10	113	1,197
Michigan	Grand Rapids	1,084	1.03	31	1,115
Minnesota	Saint Paul	1,084	1.09	96	1,180
Mississippi	Jackson	1,084	0.95	(58)	1,026
Missouri	St. Louis	1,084	1.10	108	1,192
Missouri	Kansas City	1,084	1.07	72	1,156
Montana	Great Falls	1,084	0.97	(36)	1,047
Nebraska	Omaha	1,084	0.97	(29)	1,055
New Hampshire	Concord	1,084	1.18	192	1,276
New Jersey	Newark	1,084	1.21	223	1,306
New Mexico	Albuquerque	1,084	0.97	(27)	1,056
New York	New York	1,084	1.58	634	1,717
New York	Syracuse	1,084	1.19	206	1,290
Nevada	Las Vegas	1,084	1.11	124	1,208
North Carolina	Charlotte	1,084	0.96	(43)	1,040
North Dakota	Bismarck	1,084	1.02	22	1,105
Oklahoma	Oklahoma City	1,084	1.00	(1)	1,083
Oklahoma	Tulsa	1,084	0.93	(72)	1,011
Ohio	Cincinnati	1,084	0.93	(72)	1,011
Oregon	Portland	1,084	1.21	229	1,313
Pennsylvania	Philadelphia	1,084	1.36	387	1,470
Pennsylvania	Wilkes-Barre	1,084	1.19	210	1,294
Rhode Island	Providence	1,084	1.25	273	1,357
South Carolina	Charleston	1,084	0.95	(57)	1,027
South Carolina	Spartanburg (Asheville, NC)	1,084	0.96	(43)	1,040
South Dakota	Rapid City	1,084	0.98	(26)	1,058
Tennessee	Knoxville (Nashville)	1,084	0.97	(32)	1,052
Texas	Houston	1,084	0.93	(74)	1,009
Utah	Salt Lake City	1,084	0.97	(34)	1,050
Vermont	Burlington	1,084	1.01	15	1,098
Virginia	Alexandria	1,084	1.15	158	1,242
Virginia	Lynchburg	1,084	1.08	87	1,171
Washington	Seattle	1,084	1.13	136	1,220
Washington	Spokane	1,084	1.03	38	1,122
West Virginia	Charleston	1,084	1.04	38	1,122
Wisconsin	Green Bay	1,084	1.04	42	1,126
Wyoming	Cheyenne	1,084	0.99	(11)	1,072

Table 1 9 — Location Adjustment for Combined-Cycle Gas Turbine (with 90% CCS)
(2019 Dollars)
Case Configuration: 430 MW, H-Class 1x1x1

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	2,481	0.98	(49)	2,432
Arizona	Phoenix	2,481	0.99	(26)	2,454
Arkansas	Little Rock	2,481	0.98	(42)	2,439
California	Bakersfield	2,481	1.08	191	2,672
California	Los Angeles	2,481	1.08	205	2,685
California	Modesto (instead of Redding)	2,481	1.08	198	2,679
California	Sacramento	2,481	1.09	217	2,697
California	San Francisco	2,481	1.14	353	2,834
Colorado	Denver	2,481	0.98	(39)	2,442
Connecticut	Hartford	2,481	1.07	169	2,650
Delaware	Dover	2,481	1.06	152	2,632
District of Columbia	Washington	2,481	1.01	28	2,509
Florida	Tallahassee	2,481	0.97	(66)	2,415
Florida	Tampa	2,481	0.98	(50)	2,431
Georgia	Atlanta	2,481	0.99	(26)	2,454
Idaho	Boise	2,481	1.01	15	2,496
Illinois	Chicago	2,481	1.11	264	2,745
Illinois	Joliet	2,481	1.09	228	2,709
Indiana	Indianapolis	2,481	1.00	12	2,492
Iowa	Davenport	2,481	1.02	38	2,519
Iowa	Waterloo	2,481	0.98	(41)	2,440
Kansas	Wichita	2,481	0.98	(38)	2,443
Kentucky	Louisville	2,481	1.00	(4)	2,477
Louisiana	New Orleans	2,481	0.98	(40)	2,441
Maine	Portland	2,481	1.00	6	2,487
Maryland	Baltimore	2,481	1.01	19	2,500
Massachusetts	Boston	2,481	1.09	225	2,706
Michigan	Detroit	2,481	1.05	125	2,606
Michigan	Grand Rapids	2,481	1.01	34	2,515
Minnesota	Saint Paul	2,481	1.04	101	2,582
Mississippi	Jackson	2,481	0.97	(64)	2,417
Missouri	St. Louis	2,481	1.05	131	2,612
Missouri	Kansas City	2,481	1.03	80	2,561
Montana	Great Falls	2,481	0.98	(42)	2,439
Nebraska	Omaha	2,481	0.99	(31)	2,449
New Hampshire	Concord	2,481	1.02	61	2,542
New Jersey	Newark	2,481	1.10	248	2,729
New Mexico	Albuquerque	2,481	0.99	(22)	2,459
New York	New York	2,481	1.20	489	2,970
New York	Syracuse	2,481	1.03	67	2,548
Nevada	Las Vegas	2,481	1.06	146	2,627
North Carolina	Charlotte	2,481	0.98	(48)	2,433
North Dakota	Bismarck	2,481	1.01	19	2,499
Oklahoma	Oklahoma City	2,481	1.00	(2)	2,479
Oklahoma	Tulsa	2,481	0.97	(81)	2,400
Ohio	Cincinnati	2,481	0.97	(81)	2,400
Oregon	Portland	2,481	1.04	98	2,579
Pennsylvania	Philadelphia	2,481	1.10	246	2,727
Pennsylvania	Wilkes-Barre	2,481	1.03	72	2,552
Rhode Island	Providence	2,481	1.06	137	2,618
South Carolina	Charleston	2,481	0.98	(42)	2,438
South Carolina	Spartanburg (Asheville, NC)	2,481	0.98	(44)	2,437
South Dakota	Rapid City	2,481	0.99	(35)	2,446
Tennessee	Knoxville (Nashville)	2,481	0.99	(25)	2,456
Texas	Houston	2,481	0.97	(82)	2,399
Utah	Salt Lake City	2,481	0.99	(28)	2,453
Vermont	Burlington	2,481	1.01	35	2,516
Virginia	Alexandria	2,481	1.01	21	2,502
Virginia	Lynchburg	2,481	0.98	(51)	2,430
Washington	Seattle	2,481	1.06	160	2,641
Washington	Spokane	2,481	1.02	46	2,527
West Virginia	Charleston	2,481	1.02	42	2,523
Wisconsin	Green Bay	2,481	1.02	40	2,521
Wyoming	Cheyenne	2,481	0.99	(15)	2,466

Table 1 10 — Location Adjustment for Fuel Cell (Molten Carbonate or Other Commercially Viable Technology)
(2019 Dollars)
Case Configuration: 10 MW (4 x 2.8 MW MCFC)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	6,700	0.99	(66)	6,634
Arizona	Phoenix	6,700	0.99	(74)	6,626
Arkansas	Little Rock	6,700	1.00	10	6,710
California	Bakersfield	6,700	1.13	858	7,558
California	Los Angeles	6,700	1.14	907	7,607
California	Modesto (instead of Redding)	6,700	1.13	892	7,592
California	Sacramento	6,700	1.14	953	7,652
California	San Francisco	6,700	1.19	1,284	7,983
Colorado	Denver	6,700	0.98	(157)	6,543
Connecticut	Hartford	6,700	1.11	729	7,429
Delaware	Dover	6,700	1.07	463	7,163
District of Columbia	Washington	6,700	1.02	144	6,844
Florida	Tallahassee	6,700	0.97	(205)	6,495
Florida	Tampa	6,700	0.98	(136)	6,564
Georgia	Atlanta	6,700	1.00	32	6,731
Idaho	Boise	6,700	1.02	147	6,847
Illinois	Chicago	6,700	1.16	1,051	7,750
Illinois	Joliet	6,700	1.13	874	7,573
Indiana	Indianapolis	6,700	1.02	161	6,861
Iowa	Davenport	6,700	1.03	190	6,890
Iowa	Waterloo	6,700	0.99	(63)	6,637
Kansas	Wichita	6,700	0.99	(57)	6,643
Kentucky	Louisville	6,700	1.01	97	6,797
Louisiana	New Orleans	6,700	1.00	14	6,713
Maine	Portland	6,700	1.01	97	6,797
Maryland	Baltimore	6,700	1.02	131	6,831
Massachusetts	Boston	6,700	1.14	905	7,605
Michigan	Detroit	6,700	1.07	455	7,154
Michigan	Grand Rapids	6,700	1.02	119	6,819
Minnesota	Saint Paul	6,700	1.06	391	7,091
Mississippi	Jackson	6,700	0.97	(205)	6,495
Missouri	St. Louis	6,700	1.10	684	7,384
Missouri	Kansas City	6,700	1.05	338	7,038
Montana	Great Falls	6,700	0.98	(106)	6,594
Nebraska	Omaha	6,700	0.99	(39)	6,661
New Hampshire	Concord	6,700	1.07	450	7,150
New Jersey	Newark	6,700	1.14	961	7,661
New Mexico	Albuquerque	6,700	1.02	108	6,808
New York	New York	6,700	1.27	1,834	8,533
New York	Syracuse	6,700	1.04	254	6,954
Nevada	Las Vegas	6,700	1.10	693	7,393
North Carolina	Charlotte	6,700	0.98	(138)	6,562
North Dakota	Bismarck	6,700	1.00	9	6,708
Oklahoma	Oklahoma City	6,700	1.00	0	6,700
Oklahoma	Tulsa	6,700	0.96	(268)	6,431
Ohio	Cincinnati	6,700	0.96	(270)	6,430
Oregon	Portland	6,700	1.07	496	7,196
Pennsylvania	Philadelphia	6,700	1.13	892	7,592
Pennsylvania	Wilkes-Barre	6,700	1.05	325	7,024
Rhode Island	Providence	6,700	1.10	650	7,349
South Carolina	Charleston	6,700	1.02	156	6,856
South Carolina	Spartanburg (Asheville, NC)	6,700	0.99	(56)	6,644
South Dakota	Rapid City	6,700	0.98	(111)	6,589
Tennessee	Knoxville (Nashville)	6,700	1.01	51	6,751
Texas	Houston	6,700	0.96	(270)	6,429
Utah	Salt Lake City	6,700	1.02	113	6,813
Vermont	Burlington	6,700	1.07	458	7,157
Virginia	Alexandria	6,700	1.02	124	6,824
Virginia	Lynchburg	6,700	0.98	(118)	6,582
Washington	Seattle	6,700	1.11	705	7,405
Washington	Spokane	6,700	1.04	243	6,943
West Virginia	Charleston	6,700	1.02	149	6,848
Wisconsin	Green Bay	6,700	1.02	113	6,812
Wyoming	Cheyenne	6,700	0.99	(66)	6,633

Table 1 11 — Location Adjustment for Advanced Nuclear AP 1000 (Brownfield Site)
(2019 Dollars)

Case Configuration: 2 x 1117 MW, PWR

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	6,041	0.99	(53)	5,988
Arizona	Phoenix	6,041	0.98	(147)	5,894
Arkansas	Little Rock	6,041	1.02	122	6,163
California	Bakersfield	6,041	1.22	1,305	7,346
California	Los Angeles	6,041	1.22	1,339	7,380
California	Modesto (instead of Redding)	6,041	1.22	1,358	7,399
California	Sacramento	6,041	1.24	1,443	7,484
California	San Francisco	6,041	1.30	1,830	7,871
Colorado	Denver	6,041	0.96	(227)	5,815
Connecticut	Hartford	6,041	1.16	946	6,987
Delaware	Dover	6,041	1.10	602	6,643
District of Columbia	Washington	6,041	1.02	146	6,188
Florida	Tallahassee	6,041	0.95	(280)	5,761
Florida	Tampa	6,041	0.97	(151)	5,890
Georgia	Atlanta	6,041	1.01	61	6,103
Idaho	Boise	6,041	1.04	258	6,300
Illinois	Chicago	6,041	1.23	1,415	7,456
Illinois	Joliet	6,041	1.20	1,207	7,249
Indiana	Indianapolis	6,041	1.05	274	6,315
Iowa	Davenport	6,041	1.04	231	6,272
Iowa	Waterloo	6,041	0.98	(134)	5,907
Kansas	Wichita	6,041	0.98	(130)	5,912
Kentucky	Louisville	6,041	1.03	204	6,245
Louisiana	New Orleans	6,041	1.02	95	6,137
Maine	Portland	6,041	1.04	217	6,258
Maryland	Baltimore	6,041	1.03	160	6,202
Massachusetts	Boston	6,041	1.20	1,216	7,257
Michigan	Detroit	6,041	1.10	634	6,675
Michigan	Grand Rapids	6,041	1.04	225	6,267
Minnesota	Saint Paul	6,041	1.06	389	6,430
Mississippi	Jackson	6,041	0.95	(294)	5,747
Missouri	St. Louis	6,041	1.18	1,061	7,103
Missouri	Kansas City	6,041	1.07	418	6,459
Montana	Great Falls	6,041	0.97	(186)	5,855
Nebraska	Omaha	6,041	0.98	(100)	5,941
New Hampshire	Concord	6,041	1.11	649	6,690
New Jersey	Newark	6,041	1.21	1,297	7,338
New Mexico	Albuquerque	6,041	1.03	196	6,237
New York	New York	6,041	1.42	2,560	8,601
New York	Syracuse	6,041	1.06	344	6,385
Nevada	Las Vegas	6,041	1.18	1,095	7,136
North Carolina	Charlotte	6,041	0.97	(203)	5,838
North Dakota	Bismarck	6,041	1.00	(4)	6,037
Oklahoma	Oklahoma City	6,041	1.00	4	6,045
Oklahoma	Tulsa	6,041	0.94	(387)	5,654
Ohio	Cincinnati	6,041	0.94	(389)	5,652
Oregon	Portland	6,041	1.13	777	6,818
Pennsylvania	Philadelphia	6,041	1.20	1,204	7,245
Pennsylvania	Wilkes-Barre	6,041	1.08	463	6,504
Rhode Island	Providence	6,041	1.15	893	6,935
South Carolina	Charleston	6,041	1.07	407	6,448
South Carolina	Spartanburg (Asheville, NC)	6,041	0.99	(50)	5,992
South Dakota	Rapid City	6,041	0.95	(287)	5,754
Tennessee	Knoxville (Nashville)	6,041	1.03	197	6,238
Texas	Houston	6,041	0.94	(339)	5,703
Utah	Salt Lake City	6,041	1.04	239	6,280
Vermont	Burlington	6,041	1.15	892	6,933
Virginia	Alexandria	6,041	1.02	110	6,151
Virginia	Lynchburg	6,041	0.96	(214)	5,827
Washington	Seattle	6,041	1.18	1,059	7,100
Washington	Spokane	6,041	1.07	447	6,488
West Virginia	Charleston	6,041	1.03	210	6,252
Wisconsin	Green Bay	6,041	1.01	63	6,105
Wyoming	Cheyenne	6,041	0.98	(107)	5,935

Table 1 12 — Location Adjustment for Small Modular Reactor (SMR) Nuclear Power Plant (2019 Dollars)
Case Configuration: 600 MW

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	6,191	0.97	(204)	5,987
Arizona	Phoenix	6,191	0.98	(97)	6,094
Arkansas	Little Rock	6,191	0.97	(166)	6,025
California	Bakersfield	6,191	1.20	1,242	7,433
California	Los Angeles	6,191	1.21	1,270	7,461
California	Modesto (instead of Redding)	6,191	1.21	1,309	7,500
California	Sacramento	6,191	1.23	1,402	7,593
California	San Francisco	6,191	1.30	1,855	8,046
Colorado	Denver	6,191	0.97	(212)	5,979
Connecticut	Hartford	6,191	1.17	1,033	7,224
Delaware	Dover	6,191	1.14	850	7,041
District of Columbia	Washington	6,191	1.02	135	6,326
Florida	Tallahassee	6,191	0.94	(345)	5,845
Florida	Tampa	6,191	0.96	(228)	5,963
Georgia	Atlanta	6,191	0.99	(70)	6,121
Idaho	Boise	6,191	1.03	202	6,392
Illinois	Chicago	6,191	1.27	1,673	7,864
Illinois	Joliet	6,191	1.23	1,429	7,620
Indiana	Indianapolis	6,191	1.03	165	6,356
Iowa	Davenport	6,191	1.05	282	6,473
Iowa	Waterloo	6,191	0.97	(160)	6,031
Kansas	Wichita	6,191	0.98	(142)	6,049
Kentucky	Louisville	6,191	1.01	85	6,276
Louisiana	New Orleans	6,191	0.98	(135)	6,056
Maine	Portland	6,191	1.03	202	6,393
Maryland	Baltimore	6,191	1.02	151	6,342
Massachusetts	Boston	6,191	1.21	1,311	7,502
Michigan	Detroit	6,191	1.12	754	6,944
Michigan	Grand Rapids	6,191	1.04	274	6,465
Minnesota	Saint Paul	6,191	1.10	628	6,819
Mississippi	Jackson	6,191	0.95	(340)	5,851
Missouri	St. Louis	6,191	1.14	867	7,058
Missouri	Kansas City	6,191	1.08	490	6,681
Montana	Great Falls	6,191	0.97	(182)	6,009
Nebraska	Omaha	6,191	0.98	(126)	6,065
New Hampshire	Concord	6,191	1.08	510	6,701
New Jersey	Newark	6,191	1.24	1,467	7,658
New Mexico	Albuquerque	6,191	0.99	(37)	6,154
New York	New York	6,191	1.47	2,941	9,132
New York	Syracuse	6,191	1.07	404	6,595
Nevada	Las Vegas	6,191	1.16	999	7,189
North Carolina	Charlotte	6,191	0.96	(238)	5,953
North Dakota	Bismarck	6,191	1.03	170	6,361
Oklahoma	Oklahoma City	6,191	1.01	40	6,231
Oklahoma	Tulsa	6,191	0.93	(436)	5,755
Ohio	Cincinnati	6,191	0.93	(438)	5,753
Oregon	Portland	6,191	1.10	634	6,825
Pennsylvania	Philadelphia	6,191	1.22	1,359	7,550
Pennsylvania	Wilkes-Barre	6,191	1.08	525	6,716
Rhode Island	Providence	6,191	1.15	902	7,093
South Carolina	Charleston	6,191	0.98	(127)	6,064
South Carolina	Spartanburg (Asheville, NC)	6,191	0.97	(187)	6,004
South Dakota	Rapid City	6,191	0.97	(168)	6,023
Tennessee	Knoxville (Nashville)	6,191	0.99	(84)	6,107
Texas	Houston	6,191	0.93	(422)	5,769
Utah	Salt Lake City	6,191	1.00	(16)	6,175
Vermont	Burlington	6,191	1.07	444	6,635
Virginia	Alexandria	6,191	1.01	93	6,284
Virginia	Lynchburg	6,191	0.96	(245)	5,946
Washington	Seattle	6,191	1.15	923	7,114
Washington	Spokane	6,191	1.06	385	6,576
West Virginia	Charleston	6,191	1.04	263	6,454
Wisconsin	Green Bay	6,191	1.05	285	6,476
Wyoming	Cheyenne	6,191	0.99	(53)	6,138

Table 1 13 — Location Adjustment for Dedicated Biomass Plant
(2019 Dollars)
Case Configuration: 50 MW, Wood

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	4,097	0.96	(160)	3,937
Arizona	Phoenix	4,097	1.11	457	4,554
Arkansas	Little Rock	4,097	0.96	(144)	3,953
California	Bakersfield	4,097	1.30	1,247	5,344
California	Los Angeles	4,097	1.32	1,318	5,415
California	Modesto (instead of Redding)	4,097	1.31	1,259	5,356
California	Sacramento	4,097	1.33	1,360	5,457
California	San Francisco	4,097	1.47	1,907	6,004
Colorado	Denver	4,097	1.09	381	4,478
Connecticut	Hartford	4,097	1.29	1,203	5,300
Delaware	Dover	4,097	1.27	1,124	5,221
District of Columbia	Washington	4,097	1.17	685	4,782
Florida	Tallahassee	4,097	0.95	(214)	3,883
Florida	Tampa	4,097	0.96	(170)	3,927
Georgia	Atlanta	4,097	0.98	(71)	4,026
Idaho	Boise	4,097	1.02	73	4,170
Illinois	Chicago	4,097	1.23	947	5,044
Illinois	Joliet	4,097	1.20	806	4,903
Indiana	Indianapolis	4,097	1.02	77	4,174
Iowa	Davenport	4,097	1.04	153	4,250
Iowa	Waterloo	4,097	0.98	(96)	4,001
Kansas	Wichita	4,097	0.98	(81)	4,016
Kentucky	Louisville	4,097	1.00	(2)	4,095
Louisiana	New Orleans	4,097	0.97	(127)	3,970
Maine	Portland	4,097	1.02	72	4,169
Maryland	Baltimore	4,097	1.03	121	4,218
Massachusetts	Boston	4,097	1.34	1,403	5,500
Michigan	Detroit	4,097	1.10	418	4,515
Michigan	Grand Rapids	4,097	1.03	142	4,240
Minnesota	Saint Paul	4,097	1.09	385	4,482
Mississippi	Jackson	4,097	0.95	(210)	3,887
Missouri	St. Louis	4,097	1.11	464	4,562
Missouri	Kansas City	4,097	1.07	291	4,388
Montana	Great Falls	4,097	0.97	(106)	3,991
Nebraska	Omaha	4,097	0.99	(52)	4,045
New Hampshire	Concord	4,097	1.19	774	4,872
New Jersey	Newark	4,097	1.22	891	4,988
New Mexico	Albuquerque	4,097	1.00	(1)	4,096
New York	New York	4,097	1.61	2,505	6,602
New York	Syracuse	4,097	1.19	782	4,879
Nevada	Las Vegas	4,097	1.14	553	4,650
North Carolina	Charlotte	4,097	0.96	(161)	3,936
North Dakota	Bismarck	4,097	1.01	56	4,153
Oklahoma	Oklahoma City	4,097	1.00	(12)	4,085
Oklahoma	Tulsa	4,097	0.93	(272)	3,825
Ohio	Cincinnati	4,097	0.93	(273)	3,824
Oregon	Portland	4,097	1.22	919	5,016
Pennsylvania	Philadelphia	4,097	1.37	1,531	5,629
Pennsylvania	Wilkes-Barre	4,097	1.21	853	4,950
Rhode Island	Providence	4,097	1.26	1,055	5,152
South Carolina	Charleston	4,097	0.96	(151)	3,946
South Carolina	Spartanburg (Asheville, NC)	4,097	0.97	(124)	3,973
South Dakota	Rapid City	4,097	0.98	(66)	4,031
Tennessee	Knoxville (Nashville)	4,097	0.97	(124)	3,973
Texas	Houston	4,097	0.93	(297)	3,801
Utah	Salt Lake City	4,097	0.98	(65)	4,032
Vermont	Burlington	4,097	1.02	93	4,190
Virginia	Alexandria	4,097	1.16	661	4,758
Virginia	Lynchburg	4,097	1.09	353	4,451
Washington	Seattle	4,097	1.13	542	4,639
Washington	Spokane	4,097	1.04	144	4,241
West Virginia	Charleston	4,097	1.04	152	4,249
Wisconsin	Green Bay	4,097	1.04	154	4,251
Wyoming	Cheyenne	4,097	1.00	(6)	4,091

Table 1 14 — Location Adjustment for Biomass Co-firing Retrofit onto Existing Coal Plant
(2019 Dollars)
Case Configuration: 300 MWnet with 30 MW of Added Biomass

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	705	0.94	(43)	662
Arizona	Phoenix	705	0.98	(15)	690
Arkansas	Little Rock	705	0.94	(41)	664
California	Bakersfield	705	1.21	145	850
California	Los Angeles	705	1.23	159	864
California	Modesto (instead of Redding)	705	1.21	148	852
California	Sacramento	705	1.24	168	873
California	San Francisco	705	1.39	278	983
Colorado	Denver	705	0.96	(25)	680
Connecticut	Hartford	705	1.20	138	843
Delaware	Dover	705	1.18	125	830
District of Columbia	Washington	705	1.05	35	740
Florida	Tallahassee	705	0.92	(53)	652
Florida	Tampa	705	0.94	(44)	661
Georgia	Atlanta	705	0.97	(23)	682
Idaho	Boise	705	1.02	15	720
Illinois	Chicago	705	1.30	214	919
Illinois	Joliet	705	1.26	182	887
Indiana	Indianapolis	705	1.02	15	720
Iowa	Davenport	705	1.05	35	740
Iowa	Waterloo	705	0.97	(22)	683
Kansas	Wichita	705	0.97	(18)	687
Kentucky	Louisville	705	1.00	(2)	702
Louisiana	New Orleans	705	0.95	(36)	668
Maine	Portland	705	1.02	16	720
Maryland	Baltimore	705	1.04	27	732
Massachusetts	Boston	705	1.25	178	883
Michigan	Detroit	705	1.13	95	799
Michigan	Grand Rapids	705	1.05	32	737
Minnesota	Saint Paul	705	1.13	89	794
Mississippi	Jackson	705	0.93	(52)	653
Missouri	St. Louis	705	1.14	101	806
Missouri	Kansas City	705	1.09	66	770
Montana	Great Falls	705	0.97	(24)	681
Nebraska	Omaha	705	0.98	(12)	693
New Hampshire	Concord	705	1.07	50	755
New Jersey	Newark	705	1.28	201	905
New Mexico	Albuquerque	705	0.99	(8)	696
New York	New York	705	1.57	400	1,105
New York	Syracuse	705	1.08	55	759
Nevada	Las Vegas	705	1.17	122	827
North Carolina	Charlotte	705	0.95	(36)	668
North Dakota	Bismarck	705	1.02	15	719
Oklahoma	Oklahoma City	705	1.00	(2)	702
Oklahoma	Tulsa	705	0.91	(61)	644
Ohio	Cincinnati	705	0.91	(61)	643
Oregon	Portland	705	1.11	79	784
Pennsylvania	Philadelphia	705	1.29	205	909
Pennsylvania	Wilkes-Barre	705	1.10	69	774
Rhode Island	Providence	705	1.15	108	813
South Carolina	Charleston	705	0.93	(46)	658
South Carolina	Spartanburg (Asheville, NC)	705	0.95	(34)	670
South Dakota	Rapid City	705	0.98	(13)	692
Tennessee	Knoxville (Nashville)	705	0.95	(32)	673
Texas	Houston	705	0.90	(67)	638
Utah	Salt Lake City	705	0.97	(18)	687
Vermont	Burlington	705	1.02	14	719
Virginia	Alexandria	705	1.04	30	735
Virginia	Lynchburg	705	0.96	(31)	673
Washington	Seattle	705	1.17	119	824
Washington	Spokane	705	1.04	31	736
West Virginia	Charleston	705	1.05	35	739
Wisconsin	Green Bay	705	1.05	37	742
Wyoming	Cheyenne	705	1.00	(1)	704

Table 1 15 — Location Adjustment for Geothermal (Representative Plant Excluding Exploration and Production of Resource) (2019 Dollars)
Case Configuration: 50 MW

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	2,521	1.14	356	2,877
California	Los Angeles	2,521	1.15	377	2,898
California	Modesto (instead of Redding)	2,521	1.15	373	2,894
California	Sacramento	2,521	1.16	401	2,922
California	San Francisco	2,521	1.22	560	3,081
Colorado	Denver	N/A	N/A	N/A	N/A
Connecticut	Hartford	N/A	N/A	N/A	N/A
Delaware	Dover	N/A	N/A	N/A	N/A
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	N/A	N/A	N/A	N/A
Idaho	Boise	2,521	1.02	50	2,571
Illinois	Chicago	N/A	N/A	N/A	N/A
Illinois	Joliet	N/A	N/A	N/A	N/A
Indiana	Indianapolis	N/A	N/A	N/A	N/A
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	N/A	N/A	N/A	N/A
Maryland	Baltimore	N/A	N/A	N/A	N/A
Massachusetts	Boston	N/A	N/A	N/A	N/A
Michigan	Detroit	N/A	N/A	N/A	N/A
Michigan	Grand Rapids	N/A	N/A	N/A	N/A
Minnesota	Saint Paul	N/A	N/A	N/A	N/A
Mississippi	Jackson	N/A	N/A	N/A	N/A
Missouri	St. Louis	N/A	N/A	N/A	N/A
Missouri	Kansas City	N/A	N/A	N/A	N/A
Montana	Great Falls	N/A	N/A	N/A	N/A
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Concord	N/A	N/A	N/A	N/A
New Jersey	Newark	N/A	N/A	N/A	N/A
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	N/A	N/A	N/A	N/A
New York	Syracuse	N/A	N/A	N/A	N/A
Nevada	Las Vegas	2,521	1.11	277	2,798
North Carolina	Charlotte	N/A	N/A	N/A	N/A
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oklahoma	Tulsa	N/A	N/A	N/A	N/A
Ohio	Cincinnati	N/A	N/A	N/A	N/A
Oregon	Portland	2,521	1.07	183	2,704
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Wilkes-Barre	N/A	N/A	N/A	N/A
Rhode Island	Providence	N/A	N/A	N/A	N/A
South Carolina	Charleston	N/A	N/A	N/A	N/A
South Carolina	Spartanburg (Asheville, NC)	N/A	N/A	N/A	N/A
South Dakota	Rapid City	N/A	N/A	N/A	N/A
Tennessee	Knoxville (Nashville)	N/A	N/A	N/A	N/A
Texas	Houston	N/A	N/A	N/A	N/A
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	N/A	N/A	N/A	N/A
Virginia	Lynchburg	N/A	N/A	N/A	N/A
Washington	Seattle	2,521	1.11	276	2,797
Washington	Spokane	2,521	1.04	89	2,610
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	N/A	N/A	N/A	N/A
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1 16 — Location Adjustment for 30-MW Internal Combustion Engines (4 x 9.1MW)
(2019 Dollars)
Case Configuration: 1100 MW, H-Class, 2x2x1

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,563	0.98	(39)	1,525
Arizona	Phoenix	1,563	0.98	(28)	1,536
Arkansas	Little Rock	1,563	0.99	(23)	1,540
California	Bakersfield	1,563	1.16	249	1,812
California	Los Angeles	1,563	1.16	258	1,821
California	Modesto (instead of Redding)	1,563	1.16	248	1,812
California	Sacramento	1,563	1.17	267	1,831
California	San Francisco	1,563	1.25	394	1,957
Colorado	Denver	1,563	0.97	(49)	1,515
Connecticut	Hartford	1,563	1.14	213	1,776
Delaware	Dover	1,563	1.09	146	1,709
District of Columbia	Washington	1,563	1.02	36	1,599
Florida	Tallahassee	1,563	0.96	(67)	1,497
Florida	Tampa	1,563	0.97	(50)	1,513
Georgia	Atlanta	1,563	0.99	(12)	1,551
Idaho	Boise	1,563	1.02	32	1,595
Illinois	Chicago	1,563	1.20	320	1,884
Illinois	Joliet	1,563	1.17	268	1,831
Indiana	Indianapolis	1,563	1.02	33	1,596
Iowa	Davenport	1,563	1.04	55	1,619
Iowa	Waterloo	1,563	0.98	(27)	1,536
Kansas	Wichita	1,563	0.99	(23)	1,540
Kentucky	Louisville	1,563	1.01	13	1,576
Louisiana	New Orleans	1,563	0.99	(20)	1,543
Maine	Portland	1,563	1.01	23	1,586
Maryland	Baltimore	1,563	1.02	31	1,594
Massachusetts	Boston	1,563	1.17	270	1,833
Michigan	Detroit	1,563	1.09	135	1,698
Michigan	Grand Rapids	1,563	1.02	36	1,599
Minnesota	Saint Paul	1,563	1.08	122	1,685
Mississippi	Jackson	1,563	0.96	(66)	1,497
Missouri	St. Louis	1,563	1.12	180	1,744
Missouri	Kansas City	1,563	1.06	99	1,663
Montana	Great Falls	1,563	0.98	(34)	1,530
Nebraska	Omaha	1,563	0.99	(20)	1,543
New Hampshire	Concord	1,563	1.06	101	1,664
New Jersey	Newark	1,563	1.18	288	1,851
New Mexico	Albuquerque	1,563	1.00	4	1,567
New York	New York	1,563	1.36	566	2,129
New York	Syracuse	1,563	1.05	81	1,644
Nevada	Las Vegas	1,563	1.12	191	1,755
North Carolina	Charlotte	1,563	0.97	(47)	1,517
North Dakota	Bismarck	1,563	1.00	5	1,568
Oklahoma	Oklahoma City	1,563	1.00	1	1,564
Oklahoma	Tulsa	1,563	0.95	(85)	1,479
Ohio	Cincinnati	1,563	0.95	(85)	1,478
Oregon	Portland	1,563	1.09	135	1,698
Pennsylvania	Philadelphia	1,563	1.18	274	1,838
Pennsylvania	Wilkes-Barre	1,563	1.06	91	1,654
Rhode Island	Providence	1,563	1.12	184	1,747
South Carolina	Charleston	1,563	1.00	(5)	1,558
South Carolina	Spartanburg (Asheville, NC)	1,563	0.98	(31)	1,532
South Dakota	Rapid City	1,563	0.98	(35)	1,528
Tennessee	Knoxville (Nashville)	1,563	0.99	(9)	1,554
Texas	Houston	1,563	0.94	(90)	1,473
Utah	Salt Lake City	1,563	1.00	3	1,567
Vermont	Burlington	1,563	1.06	86	1,650
Virginia	Alexandria	1,563	1.02	30	1,593
Virginia	Lynchburg	1,563	0.97	(48)	1,516
Washington	Seattle	1,563	1.13	198	1,761
Washington	Spokane	1,563	1.04	56	1,619
West Virginia	Charleston	1,563	1.03	46	1,609
Wisconsin	Green Bay	1,563	1.03	44	1,607
Wyoming	Cheyenne	1,563	0.99	(16)	1,547

Table 1 17 — Location Adjustment for Hydroelectric (Representative Plant in New-Stream-Reach Location)
(2019 Dollars)
Case Configuration: 100 MW

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	5,316	1.16	871	6,187
California	Los Angeles	5,316	1.12	659	5,975
California	Modesto (instead of Redding)	5,316	1.21	1,100	6,417
California	Sacramento	5,316	1.21	1,092	6,408
California	San Francisco	5,316	1.27	1,420	6,737
Colorado	Denver	5,316	1.02	94	5,410
Connecticut	Hartford	5,316	1.17	920	6,236
Delaware	Dover	N/A	N/A	N/A	N/A
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	N/A	N/A	N/A	N/A
Idaho	Boise	5,316	0.75	(1,345)	3,971
Illinois	Chicago	N/A	N/A	N/A	N/A
Illinois	Joliet	N/A	N/A	N/A	N/A
Indiana	Indianapolis	N/A	N/A	N/A	N/A
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	5,316	1.03	163	5,479
Maryland	Baltimore	N/A	N/A	N/A	N/A
Massachusetts	Boston	N/A	N/A	N/A	N/A
Michigan	Detroit	N/A	N/A	N/A	N/A
Michigan	Grand Rapids	N/A	N/A	N/A	N/A
Minnesota	Saint Paul	N/A	N/A	N/A	N/A
Mississippi	Jackson	N/A	N/A	N/A	N/A
Missouri	St. Louis	5,316	1.15	771	6,088
Missouri	Kansas City	5,316	1.06	332	5,648
Montana	Great Falls	5,316	0.97	(141)	5,175
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Concord	N/A	N/A	N/A	N/A
New Jersey	Newark	N/A	N/A	N/A	N/A
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	N/A	N/A	N/A	N/A
New York	Syracuse	N/A	N/A	N/A	N/A
Nevada	Las Vegas	N/A	N/A	N/A	N/A
North Carolina	Charlotte	5,316	0.97	(161)	5,155
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oklahoma	Tulsa	N/A	N/A	N/A	N/A
Ohio	Cincinnati	5,316	0.94	(318)	4,998
Oregon	Portland	5,316	1.11	565	5,881
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Wilkes-Barre	N/A	N/A	N/A	N/A
Rhode Island	Providence	N/A	N/A	N/A	N/A
South Carolina	Charleston	N/A	N/A	N/A	N/A
South Carolina	Spartanburg (Asheville, NC)	N/A	N/A	N/A	N/A
South Dakota	Rapid City	5,316	0.96	(198)	5,119
Tennessee	Knoxville (Nashville)	N/A	N/A	N/A	N/A
Texas	Houston	N/A	N/A	N/A	N/A
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	N/A	N/A	N/A	N/A
Virginia	Lynchburg	N/A	N/A	N/A	N/A
Washington	Seattle	5,316	1.15	780	6,096
Washington	Spokane	5,316	1.06	329	5,645
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	N/A	N/A	N/A	N/A
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1 18 — Location Adjustment for Battery Storage: 4 Hours
A battery energy storage project designed primarily to provide resource adequacy and bulk energy storage.
(2019 Dollars)

Case Configuration: 50 MW / 200 MWh

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,389	1.02	24	1,413
Arizona	Phoenix	1,389	0.99	(15)	1,374
Arkansas	Little Rock	1,389	1.04	56	1,445
California	Bakersfield	1,389	1.04	57	1,446
California	Los Angeles	1,389	1.04	60	1,449
California	Modesto (instead of Redding)	1,389	1.04	55	1,444
California	Sacramento	1,389	1.04	57	1,446
California	San Francisco	1,389	1.04	60	1,449
Colorado	Denver	1,389	0.99	(12)	1,377
Connecticut	Hartford	1,389	1.02	23	1,412
Delaware	Dover	1,389	0.99	(17)	1,373
District of Columbia	Washington	1,389	1.01	9	1,398
Florida	Tallahassee	1,389	1.00	0	1,389
Florida	Tampa	1,389	1.01	7	1,396
Georgia	Atlanta	1,389	1.02	25	1,414
Idaho	Boise	1,389	1.01	19	1,408
Illinois	Chicago	1,389	1.01	15	1,404
Illinois	Joliet	1,389	1.01	12	1,401
Indiana	Indianapolis	1,389	1.02	29	1,418
Iowa	Davenport	1,389	1.00	1	1,390
Iowa	Waterloo	1,389	1.00	(1)	1,388
Kansas	Wichita	1,389	1.00	(2)	1,387
Kentucky	Louisville	1,389	1.02	28	1,417
Louisiana	New Orleans	1,389	1.03	44	1,434
Maine	Portland	1,389	1.01	11	1,400
Maryland	Baltimore	1,389	1.01	8	1,397
Massachusetts	Boston	1,389	1.02	32	1,421
Michigan	Detroit	1,389	1.00	5	1,394
Michigan	Grand Rapids	1,389	1.00	0	1,390
Minnesota	Saint Paul	1,389	0.99	(21)	1,368
Mississippi	Jackson	1,389	1.00	(4)	1,385
Missouri	St. Louis	1,389	1.05	71	1,460
Missouri	Kansas City	1,389	1.00	5	1,394
Montana	Great Falls	1,389	0.99	(8)	1,381
Nebraska	Omaha	1,389	1.00	1	1,390
New Hampshire	Concord	1,389	1.03	47	1,436
New Jersey	Newark	1,389	1.02	23	1,412
New Mexico	Albuquerque	1,389	1.04	49	1,438
New York	New York	1,389	1.03	37	1,426
New York	Syracuse	1,389	1.00	5	1,394
Nevada	Las Vegas	1,389	1.04	56	1,445
North Carolina	Charlotte	1,389	1.00	(2)	1,387
North Dakota	Bismarck	1,389	0.98	(29)	1,360
Oklahoma	Oklahoma City	1,389	1.00	(6)	1,383
Oklahoma	Tulsa	1,389	0.99	(8)	1,381
Ohio	Cincinnati	1,389	0.99	(8)	1,381
Oregon	Portland	1,389	1.04	53	1,442
Pennsylvania	Philadelphia	1,389	1.02	22	1,411
Pennsylvania	Wilkes-Barre	1,389	1.01	8	1,397
Rhode Island	Providence	1,389	1.02	33	1,422
South Carolina	Charleston	1,389	1.08	114	1,503
South Carolina	Spartanburg (Asheville, NC)	1,389	1.02	22	1,411
South Dakota	Rapid City	1,389	0.98	(31)	1,358
Tennessee	Knoxville (Nashville)	1,389	1.04	57	1,446
Texas	Houston	1,389	1.00	0	1,389
Utah	Salt Lake City	1,389	1.04	54	1,443
Vermont	Burlington	1,389	1.08	109	1,498
Virginia	Alexandria	1,389	1.01	9	1,398
Virginia	Lynchburg	1,389	1.00	(4)	1,385
Washington	Seattle	1,389	1.04	61	1,450
Washington	Spokane	1,389	1.02	26	1,415
West Virginia	Charleston	1,389	1.00	(1)	1,389
Wisconsin	Green Bay	1,389	0.98	(33)	1,356
Wyoming	Cheyenne	1,389	0.99	(13)	1,376

Table 1 19 — Location Adjustment for Battery Storage: 2 hours
(2019 Dollars)
Case Configuration: 50 MW / 100 MWh

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	845	1.02	15	860
Arizona	Phoenix	845	0.99	(9)	836
Arkansas	Little Rock	845	1.04	34	879
California	Bakersfield	845	1.04	35	880
California	Los Angeles	845	1.04	36	881
California	Modesto (instead of Redding)	845	1.04	33	878
California	Sacramento	845	1.04	34	880
California	San Francisco	845	1.04	37	882
Colorado	Denver	845	0.99	(7)	838
Connecticut	Hartford	845	1.02	14	859
Delaware	Dover	845	0.99	(10)	835
District of Columbia	Washington	845	1.01	5	851
Florida	Tallahassee	845	1.00	0	845
Florida	Tampa	845	1.00	4	849
Georgia	Atlanta	845	1.02	15	860
Idaho	Boise	845	1.01	12	857
Illinois	Chicago	845	1.01	9	854
Illinois	Joliet	845	1.01	7	853
Indiana	Indianapolis	845	1.02	18	863
Iowa	Davenport	845	1.00	1	846
Iowa	Waterloo	845	1.00	(1)	844
Kansas	Wichita	845	1.00	(1)	844
Kentucky	Louisville	845	1.02	17	862
Louisiana	New Orleans	845	1.03	27	872
Maine	Portland	845	1.01	6	852
Maryland	Baltimore	845	1.01	5	850
Massachusetts	Boston	845	1.02	19	865
Michigan	Detroit	845	1.00	3	848
Michigan	Grand Rapids	845	1.00	0	845
Minnesota	Saint Paul	845	0.99	(13)	833
Mississippi	Jackson	845	1.00	(3)	843
Missouri	St. Louis	845	1.05	43	888
Missouri	Kansas City	845	1.00	3	848
Montana	Great Falls	845	0.99	(5)	840
Nebraska	Omaha	845	1.00	0	846
New Hampshire	Concord	845	1.03	28	874
New Jersey	Newark	845	1.02	14	859
New Mexico	Albuquerque	845	1.04	30	875
New York	New York	845	1.03	23	868
New York	Syracuse	845	1.00	3	848
Nevada	Las Vegas	845	1.04	34	879
North Carolina	Charlotte	845	1.00	(1)	844
North Dakota	Bismarck	845	0.98	(18)	827
Oklahoma	Oklahoma City	845	1.00	(4)	841
Oklahoma	Tulsa	845	0.99	(5)	840
Ohio	Cincinnati	845	0.99	(5)	840
Oregon	Portland	845	1.04	32	877
Pennsylvania	Philadelphia	845	1.02	14	859
Pennsylvania	Wilkes-Barre	845	1.01	5	850
Rhode Island	Providence	845	1.02	20	865
South Carolina	Charleston	845	1.08	69	914
South Carolina	Spartanburg (Asheville, NC)	845	1.02	13	859
South Dakota	Rapid City	845	0.98	(19)	826
Tennessee	Knoxville (Nashville)	845	1.04	34	879
Texas	Houston	845	1.00	0	845
Utah	Salt Lake City	845	1.04	33	878
Vermont	Burlington	845	1.08	66	911
Virginia	Alexandria	845	1.01	5	850
Virginia	Lynchburg	845	1.00	(2)	843
Washington	Seattle	845	1.04	37	882
Washington	Spokane	845	1.02	16	861
West Virginia	Charleston	845	1.00	0	845
Wisconsin	Green Bay	845	0.98	(20)	825
Wyoming	Cheyenne	845	0.99	(7)	839

Table 1 20 — Location Adjustment for Onshore Wind, Large Plant Footprint: Great Plains Region (2019 Dollars)
Case Configuration: 200 MW, 2.8-MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,265	1.01	12	1,277
Arizona	Phoenix	1,265	0.99	(16)	1,249
Arkansas	Little Rock	1,265	1.03	35	1,301
California	Bakersfield	1,265	1.05	60	1,325
California	Los Angeles	1,265	1.05	63	1,329
California	Modesto (instead of Redding)	1,265	1.05	58	1,323
California	Sacramento	1,265	1.05	62	1,327
California	San Francisco	1,265	1.06	76	1,342
Colorado	Denver	1,265	0.99	(13)	1,252
Connecticut	Hartford	1,265	1.03	32	1,298
Delaware	Dover	1,265	1.00	(1)	1,265
District of Columbia	Washington	1,265	1.01	9	1,274
Florida	Tallahassee	1,265	1.00	(6)	1,259
Florida	Tampa	1,265	1.00	0	1,265
Georgia	Atlanta	1,265	1.01	14	1,280
Idaho	Boise	1,265	1.01	16	1,281
Illinois	Chicago	1,265	1.03	37	1,302
Illinois	Joliet	1,265	1.03	32	1,297
Indiana	Indianapolis	1,265	1.02	23	1,288
Iowa	Davenport	1,265	1.00	4	1,269
Iowa	Waterloo	1,265	0.99	(7)	1,259
Kansas	Wichita	1,265	1.00	(6)	1,259
Kentucky	Louisville	1,265	1.01	19	1,284
Louisiana	New Orleans	1,265	1.02	28	1,293
Maine	Portland	1,265	1.01	8	1,274
Maryland	Baltimore	1,265	1.01	7	1,272
Massachusetts	Boston	1,265	1.04	46	1,311
Michigan	Detroit	1,265	1.01	15	1,281
Michigan	Grand Rapids	1,265	1.00	3	1,268
Minnesota	Saint Paul	1,265	1.00	(5)	1,261
Mississippi	Jackson	1,265	0.99	(9)	1,256
Missouri	St. Louis	1,265	1.05	63	1,328
Missouri	Kansas City	1,265	1.01	12	1,277
Montana	Great Falls	1,265	0.99	(9)	1,256
Nebraska	Omaha	1,265	1.00	(3)	1,263
New Hampshire	Concord	1,265	1.03	38	1,304
New Jersey	Newark	1,265	1.03	42	1,307
New Mexico	Albuquerque	1,265	1.03	33	1,298
New York	New York	1,265	1.06	74	1,339
New York	Syracuse	1,265	1.01	11	1,277
Nevada	Las Vegas	1,265	1.04	55	1,320
North Carolina	Charlotte	1,265	1.00	(6)	1,259
North Dakota	Bismarck	1,265	0.98	(21)	1,245
Oklahoma	Oklahoma City	1,265	1.00	(5)	1,260
Oklahoma	Tulsa	1,265	0.99	(13)	1,252
Ohio	Cincinnati	1,265	0.99	(13)	1,252
Oregon	Portland	1,265	1.04	47	1,312
Pennsylvania	Philadelphia	1,265	1.03	41	1,306
Pennsylvania	Wilkes-Barre	1,265	1.01	11	1,276
Rhode Island	Providence	1,265	1.03	37	1,302
South Carolina	Charleston	1,265	1.06	76	1,342
South Carolina	Spartanburg (Asheville, NC)	1,265	1.01	11	1,277
South Dakota	Rapid City	1,265	0.98	(25)	1,240
Tennessee	Knoxville (Nashville)	1,265	1.03	36	1,301
Texas	Houston	1,265	0.99	(8)	1,257
Utah	Salt Lake City	1,265	1.03	34	1,300
Vermont	Burlington	1,265	1.06	79	1,345
Virginia	Alexandria	1,265	1.01	8	1,273
Virginia	Lynchburg	1,265	0.99	(9)	1,257
Washington	Seattle	1,265	1.05	57	1,323
Washington	Spokane	1,265	1.02	21	1,286
West Virginia	Charleston	1,265	1.00	4	1,269
Wisconsin	Green Bay	1,265	0.99	(19)	1,247
Wyoming	Cheyenne	1,265	0.99	(10)	1,255

Table 1 21 — Location Adjustment for Onshore Wind, Small Plant Footprint: Coastal Region (2019 Dollars)
Case Configuration: 50 MW, 2.8-MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,677	1.01	14	1,691
Arizona	Phoenix	1,677	0.99	(23)	1,653
Arkansas	Little Rock	1,677	1.03	46	1,722
California	Bakersfield	1,677	1.05	89	1,765
California	Los Angeles	1,677	1.06	94	1,770
California	Modesto (instead of Redding)	1,677	1.05	86	1,762
California	Sacramento	1,677	1.05	91	1,768
California	San Francisco	1,677	1.07	116	1,793
Colorado	Denver	1,677	0.99	(19)	1,658
Connecticut	Hartford	1,677	1.03	50	1,727
Delaware	Dover	1,677	1.00	4	1,680
District of Columbia	Washington	1,677	1.01	13	1,689
Florida	Tallahassee	1,677	0.99	(11)	1,666
Florida	Tampa	1,677	1.00	(3)	1,674
Georgia	Atlanta	1,677	1.01	18	1,695
Idaho	Boise	1,677	1.01	22	1,699
Illinois	Chicago	1,677	1.04	61	1,737
Illinois	Joliet	1,677	1.03	53	1,729
Indiana	Indianapolis	1,677	1.02	32	1,709
Iowa	Davenport	1,677	1.00	7	1,683
Iowa	Waterloo	1,677	0.99	(11)	1,666
Kansas	Wichita	1,677	0.99	(10)	1,667
Kentucky	Louisville	1,677	1.02	25	1,702
Louisiana	New Orleans	1,677	1.02	36	1,712
Maine	Portland	1,677	1.01	11	1,688
Maryland	Baltimore	1,677	1.01	10	1,686
Massachusetts	Boston	1,677	1.04	71	1,747
Michigan	Detroit	1,677	1.02	25	1,702
Michigan	Grand Rapids	1,677	1.00	5	1,681
Minnesota	Saint Paul	1,677	1.00	(2)	1,674
Mississippi	Jackson	1,677	0.99	(15)	1,662
Missouri	St. Louis	1,677	1.05	90	1,767
Missouri	Kansas City	1,677	1.01	19	1,695
Montana	Great Falls	1,677	0.99	(14)	1,663
Nebraska	Omaha	1,677	1.00	(5)	1,672
New Hampshire	Concord	1,677	1.03	54	1,731
New Jersey	Newark	1,677	1.04	67	1,743
New Mexico	Albuquerque	1,677	1.03	44	1,720
New York	New York	1,677	1.07	118	1,795
New York	Syracuse	1,677	1.01	18	1,695
Nevada	Las Vegas	1,677	1.05	80	1,756
North Carolina	Charlotte	1,677	0.99	(10)	1,666
North Dakota	Bismarck	1,677	0.98	(27)	1,649
Oklahoma	Oklahoma City	1,677	1.00	(7)	1,670
Oklahoma	Tulsa	1,677	0.99	(21)	1,656
Ohio	Cincinnati	1,677	0.99	(21)	1,655
Oregon	Portland	1,677	1.04	67	1,744
Pennsylvania	Philadelphia	1,677	1.04	65	1,742
Pennsylvania	Wilkes-Barre	1,677	1.01	17	1,694
Rhode Island	Providence	1,677	1.03	55	1,732
South Carolina	Charleston	1,677	1.06	101	1,778
South Carolina	Spartanburg (Asheville, NC)	1,677	1.01	14	1,690
South Dakota	Rapid City	1,677	0.98	(35)	1,642
Tennessee	Knoxville (Nashville)	1,677	1.03	46	1,723
Texas	Houston	1,677	0.99	(14)	1,662
Utah	Salt Lake City	1,677	1.03	45	1,722
Vermont	Burlington	1,677	1.06	108	1,785
Virginia	Alexandria	1,677	1.01	11	1,688
Virginia	Lynchburg	1,677	0.99	(14)	1,663
Washington	Seattle	1,677	1.05	83	1,760
Washington	Spokane	1,677	1.02	29	1,705
West Virginia	Charleston	1,677	1.00	6	1,683
Wisconsin	Green Bay	1,677	0.99	(24)	1,653
Wyoming	Cheyenne	1,677	0.99	(15)	1,662

Table 1-22 — Location Adjustment for Offshore Wind
(2019 Dollars)
Case Configuration: 40 x 10 MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	4,375	1.03	152	4,527
California	Los Angeles	4,375	1.58	2,548	6,923
California	Modesto (instead of Redding)	4,375	1.52	2,264	6,639
California	Sacramento	4,375	1.58	2,538	6,912
California	San Francisco	4,375	1.90	3,944	8,318
Colorado	Denver	N/A	N/A	N/A	N/A
Connecticut	Hartford	4,375	1.01	41	4,416
Delaware	Dover	4,375	1.31	1,344	5,719
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	4,375	1.02	87	4,462
Idaho	Boise	N/A	N/A	N/A	N/A
Illinois	Chicago	4,375	1.00	(7)	4,368
Illinois	Joliet	4,375	1.65	2,842	7,217
Indiana	Indianapolis	4,375	1.06	277	4,652
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	4,375	1.01	31	4,405
Maryland	Baltimore	4,375	1.04	180	4,555
Massachusetts	Boston	4,375	1.64	2,815	7,190
Michigan	Detroit	4,375	1.32	1,409	5,784
Michigan	Grand Rapids	4,375	1.07	318	4,693
Minnesota	Saint Paul	4,375	1.29	1,286	5,661
Mississippi	Jackson	N/A	N/A	N/A	N/A
Missouri	St. Louis	N/A	N/A	N/A	N/A
Missouri	Kansas City	N/A	N/A	N/A	N/A
Montana	Great Falls	N/A	N/A	N/A	N/A
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Concord	N/A	N/A	N/A	N/A
New Jersey	Newark	4,375	1.01	27	4,402
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	4,375	1.01	27	4,402
New York	Syracuse	4,375	1.22	962	5,337
Nevada	Las Vegas	N/A	N/A	N/A	N/A
North Carolina	Charlotte	4,375	1.00	0	4,375
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oklahoma	Tulsa	N/A	N/A	N/A	N/A
Ohio	Cincinnati	N/A	N/A	N/A	N/A
Oregon	Portland	4,375	1.00	(12)	4,363
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Wilkes-Barre	N/A	N/A	N/A	N/A
Rhode Island	Providence	4,375	1.01	27	4,402
South Carolina	Charleston	4,375	0.81	(819)	3,556
South Carolina	Spartanburg (Asheville, NC)	4,375	0.89	(494)	3,881
South Dakota	Rapid City	N/A	N/A	N/A	N/A
Tennessee	Knoxville (Nashville)	N/A	N/A	N/A	N/A
Texas	Houston	4,375	0.98	(102)	4,273
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	4,375	1.04	182	4,557
Virginia	Lynchburg	4,375	0.91	(375)	4,000
Washington	Seattle	4,375	1.35	1,531	5,905
Washington	Spokane	4,375	1.05	209	4,584
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	4,375	1.02	81	4,455
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1 23 — Location Adjustment for Concentrated Solar Thermal Plant (CSP), Power Tower, 8-hour Thermal Storage (2019 Dollars)
Case Configuration: 100 MW

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	7221	1.01	67	7288
Arizona	Phoenix	7221	0.97	(201)	7021
Arkansas	Little Rock	7221	1.05	370	7591
California	Bakersfield	7221	1.17	1,220	8441
California	Los Angeles	7221	1.18	1,269	8490
California	Modesto (instead of Redding)	7221	1.17	1,242	8463
California	Sacramento	7221	1.18	1,307	8529
California	San Francisco	7221	1.24	1,738	8959
Colorado	Denver	7221	0.97	(241)	6980
Connecticut	Hartford	7221	1.11	782	8003
Delaware	Dover	7221	1.05	346	7568
District of Columbia	Washington	7221	1.02	144	7365
Florida	Tallahassee	7221	0.97	(212)	7009
Florida	Tampa	7221	0.99	(88)	7134
Georgia	Atlanta	7221	1.02	151	7372
Idaho	Boise	7221	1.03	247	7468
Illinois	Chicago	7221	1.14	1,030	8252
Illinois	Joliet	7221	1.12	881	8102
Indiana	Indianapolis	7221	1.04	305	7527
Iowa	Davenport	7221	1.02	144	7365
Iowa	Waterloo	7221	0.98	(129)	7092
Kansas	Wichita	7221	0.98	(138)	7083
Kentucky	Louisville	7221	1.04	256	7477
Louisiana	New Orleans	7221	1.04	275	7496
Maine	Portland	7221	1.02	138	7359
Maryland	Baltimore	7221	1.02	128	7350
Massachusetts	Boston	7221	1.14	1,040	8261
Michigan	Detroit	7221	1.07	470	7692
Michigan	Grand Rapids	7221	1.02	132	7353
Minnesota	Saint Paul	7221	1.02	128	7350
Mississippi	Jackson	7221	0.97	(244)	6978
Missouri	St. Louis	7221	1.16	1,126	8347
Missouri	Kansas City	7221	1.04	313	7535
Montana	Great Falls	7221	0.97	(206)	7015
Nebraska	Omaha	7221	0.99	(105)	7117
New Hampshire	Concord	7221	1.09	666	7888
New Jersey	Newark	7221	1.14	1,027	8248
New Mexico	Albuquerque	7221	1.05	355	7577
New York	New York	7221	1.27	1,982	9203
New York	Syracuse	7221	1.04	255	7477
Nevada	Las Vegas	7221	1.14	1,033	8254
North Carolina	Charlotte	7221	0.98	(175)	7046
North Dakota	Bismarck	7221	0.98	(180)	7041
Oklahoma	Oklahoma City	7221	0.99	(38)	7184
Oklahoma	Tulsa	7221	0.95	(332)	6889
Ohio	Cincinnati	7221	0.95	(333)	6888
Oregon	Portland	7221	1.11	829	8050
Pennsylvania	Philadelphia	7221	1.14	986	8207
Pennsylvania	Wilkes-Barre	7221	1.05	326	7548
Rhode Island	Providence	7221	1.11	791	8012
South Carolina	Charleston	7221	1.12	865	8086
South Carolina	Spartanburg (Asheville, NC)	7221	1.01	58	7280
South Dakota	Rapid City	7221	0.94	(409)	6812
Tennessee	Knoxville (Nashville)	7221	1.06	452	7673
Texas	Houston	7221	0.96	(255)	6966
Utah	Salt Lake City	7221	1.06	408	7630
Vermont	Burlington	7221	1.16	1,174	8396
Virginia	Alexandria	7221	1.02	114	7335
Virginia	Lynchburg	7221	0.97	(196)	7025
Washington	Seattle	7221	1.16	1,124	8345
Washington	Spokane	7221	1.06	442	7664
West Virginia	Charleston	7221	1.02	140	7361
Wisconsin	Green Bay	7221	0.98	(167)	7054
Wyoming	Cheyenne	7221	0.98	(174)	7048

Note: Location adjustment factors are provided for all locations for the Concentrated Solar Power case. However, concentrated solar power is only feasible in locations with sufficient solar resource; therefore, it is unlikely that a concentrated solar power plant would be built in some of the locations for which factors are provided.

Table 1 24 — Location Adjustment for Solar Photovoltaic, Single-Axis Tracking (with 1.3 Inverter Loading Ratio)
(2019 Dollars)
Case Configuration: 150 MW

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,313	0.95	(68)	1,244
Arizona	Phoenix	1,313	0.97	(40)	1,273
Arkansas	Little Rock	1,313	0.98	(29)	1,284
California	Bakersfield	1,313	1.07	87	1,400
California	Los Angeles	1,313	1.09	116	1,429
California	Modesto (instead of Redding)	1,313	1.06	74	1,386
California	Sacramento	1,313	1.08	99	1,412
California	San Francisco	1,313	1.18	235	1,548
Colorado	Denver	1,313	0.98	(28)	1,285
Connecticut	Hartford	1,313	1.08	104	1,417
Delaware	Dover	1,313	1.04	56	1,369
District of Columbia	Washington	1,313	1.02	24	1,337
Florida	Tallahassee	1,313	0.96	(50)	1,263
Florida	Tampa	1,313	0.97	(37)	1,276
Georgia	Atlanta	1,313	0.98	(24)	1,289
Idaho	Boise	1,313	0.98	(32)	1,281
Illinois	Chicago	1,313	1.08	108	1,421
Illinois	Joliet	1,313	1.09	124	1,437
Indiana	Indianapolis	1,313	1.01	15	1,328
Iowa	Davenport	1,313	1.01	20	1,333
Iowa	Waterloo	1,313	0.97	(40)	1,273
Kansas	Wichita	1,313	0.98	(27)	1,286
Kentucky	Louisville	1,313	0.99	(8)	1,305
Louisiana	New Orleans	1,313	0.98	(27)	1,286
Maine	Portland	1,313	1.00	4	1,317
Maryland	Baltimore	1,313	1.01	13	1,326
Massachusetts	Boston	1,313	1.10	137	1,450
Michigan	Detroit	1,313	1.04	55	1,368
Michigan	Grand Rapids	1,313	1.01	13	1,326
Minnesota	Saint Paul	1,313	1.04	55	1,368
Mississippi	Jackson	1,313	0.97	(41)	1,272
Missouri	St. Louis	1,313	1.06	83	1,396
Missouri	Kansas City	1,313	1.03	38	1,351
Montana	Great Falls	1,313	0.98	(25)	1,288
Nebraska	Omaha	1,313	0.98	(21)	1,292
New Hampshire	Concord	1,313	1.02	20	1,333
New Jersey	Newark	1,313	1.11	151	1,464
New Mexico	Albuquerque	1,313	1.00	(5)	1,308
New York	New York	1,313	1.22	287	1,600
New York	Syracuse	1,313	1.03	34	1,347
Nevada	Las Vegas	1,313	1.07	87	1,399
North Carolina	Charlotte	1,313	0.97	(38)	1,274
North Dakota	Bismarck	1,313	0.99	(17)	1,296
Oklahoma	Oklahoma City	1,313	0.98	(29)	1,284
Oklahoma	Tulsa	1,313	0.95	(60)	1,253
Ohio	Cincinnati	1,313	0.95	(61)	1,252
Oregon	Portland	1,313	1.05	65	1,378
Pennsylvania	Philadelphia	1,313	1.13	173	1,486
Pennsylvania	Wilkes-Barre	1,313	1.02	24	1,337
Rhode Island	Providence	1,313	1.04	55	1,368
South Carolina	Charleston	1,313	1.03	44	1,357
South Carolina	Spartanburg (Asheville, NC)	1,313	1.04	55	1,368
South Dakota	Rapid City	1,313	0.96	(50)	1,263
Tennessee	Knoxville (Nashville)	1,313	1.00	(1)	1,312
Texas	Houston	1,313	0.99	(19)	1,294
Utah	Salt Lake City	1,313	0.97	(41)	1,272
Vermont	Burlington	1,313	0.97	(40)	1,273
Virginia	Alexandria	1,313	1.00	(6)	1,307
Virginia	Lynchburg	1,313	0.98	(25)	1,288
Washington	Seattle	1,313	1.03	41	1,354
Washington	Spokane	1,313	0.97	(43)	1,269
West Virginia	Charleston	1,313	1.06	77	1,390
Wisconsin	Green Bay	1,313	0.99	(16)	1,297
Wyoming	Cheyenne	1,313	1.01	13	1,326

Table 1 25 — Location Adjustment for Solar Photovoltaic, Single-Axis Tracking (with 1.3 Inverter Loading Ratio) with Battery Hybrid (2019 Dollars)

Case Configuration: PV with tracking150 MW PV50 MW/200 MWh BESS

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,755	0.98	(42)	1,713
Arizona	Phoenix	1,755	0.98	(36)	1,719
Arkansas	Little Rock	1,755	0.99	(11)	1,744
California	Bakersfield	1,755	1.07	129	1,884
California	Los Angeles	1,755	1.09	151	1,906
California	Modesto (instead of Redding)	1,755	1.07	116	1,871
California	Sacramento	1,755	1.08	137	1,892
California	San Francisco	1,755	1.14	243	1,998
Colorado	Denver	1,755	0.98	(32)	1,723
Connecticut	Hartford	1,755	1.07	125	1,881
Delaware	Dover	1,755	1.04	64	1,819
District of Columbia	Washington	1,755	1.02	29	1,785
Florida	Tallahassee	1,755	0.97	(45)	1,710
Florida	Tampa	1,755	0.98	(31)	1,724
Georgia	Atlanta	1,755	0.99	(11)	1,744
Idaho	Boise	1,755	1.00	(3)	1,753
Illinois	Chicago	1,755	1.09	162	1,918
Illinois	Joliet	1,755	1.09	152	1,908
Indiana	Indianapolis	1,755	1.01	26	1,781
Iowa	Davenport	1,755	1.02	28	1,783
Iowa	Waterloo	1,755	0.98	(32)	1,723
Kansas	Wichita	1,755	0.99	(18)	1,737
Kentucky	Louisville	1,755	1.00	5	1,760
Louisiana	New Orleans	1,755	0.99	(10)	1,745
Maine	Portland	1,755	1.01	14	1,769
Maryland	Baltimore	1,755	1.01	18	1,773
Massachusetts	Boston	1,755	1.09	164	1,919
Michigan	Detroit	1,755	1.04	68	1,824
Michigan	Grand Rapids	1,755	1.01	19	1,775
Minnesota	Saint Paul	1,755	1.04	68	1,823
Mississippi	Jackson	1,755	0.98	(41)	1,714
Missouri	St. Louis	1,755	1.06	114	1,869
Missouri	Kansas City	1,755	1.03	53	1,808
Montana	Great Falls	1,755	0.99	(23)	1,732
Nebraska	Omaha	1,755	0.99	(16)	1,740
New Hampshire	Concord	1,755	1.03	47	1,802
New Jersey	Newark	1,755	1.10	173	1,928
New Mexico	Albuquerque	1,755	1.01	12	1,768
New York	New York	1,755	1.19	332	2,087
New York	Syracuse	1,755	1.03	48	1,803
Nevada	Las Vegas	1,755	1.07	118	1,873
North Carolina	Charlotte	1,755	0.98	(33)	1,722
North Dakota	Bismarck	1,755	0.99	(11)	1,744
Oklahoma	Oklahoma City	1,755	0.99	(18)	1,737
Oklahoma	Tulsa	1,755	0.97	(59)	1,696
Ohio	Cincinnati	1,755	0.97	(60)	1,696
Oregon	Portland	1,755	1.05	84	1,839
Pennsylvania	Philadelphia	1,755	1.10	181	1,937
Pennsylvania	Wilkes-Barre	1,755	1.02	42	1,797
Rhode Island	Providence	1,755	1.05	93	1,848
South Carolina	Charleston	1,755	1.01	13	1,768
South Carolina	Spartanburg (Asheville, NC)	1,755	1.00	(7)	1,748
South Dakota	Rapid City	1,755	0.99	(26)	1,729
Tennessee	Knoxville (Nashville)	1,755	0.99	(16)	1,739
Texas	Houston	1,755	0.97	(56)	1,699
Utah	Salt Lake City	1,755	1.01	16	1,771
Vermont	Burlington	1,755	1.02	43	1,798
Virginia	Alexandria	1,755	1.02	33	1,788
Virginia	Lynchburg	1,755	0.98	(43)	1,712
Washington	Seattle	1,755	1.06	114	1,869
Washington	Spokane	1,755	1.01	17	1,772
West Virginia	Charleston	1,755	1.01	21	1,776
Wisconsin	Green Bay	1,755	1.01	12	1,767
Wyoming	Cheyenne	1,755	1.00	(6)	1,749

Appendix B. Combustion Turbine Capacity Adjustments

Performance Adjustment Factors

Capital Cost Study

Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies

Prepared by
Sargent & Lundy

Prepared for
U.S. Energy Information Administration

FINAL
Contract No. 89303019CEI00022
Project No. 13651-005

55 East Monroe | Chicago, IL 60603 | sargentlundy.com

Gas Turbine Based Capacity and Heat Rate Adjustments

LOCATION		Adjustment Basis			Simple Cycle		Combined Cyle		2 x LM6000PF+		1 x 7F.05		1 x 7HA.01 WCT		1 x 7HA.01 ACC		2 x 7HA.02 WCT		2 x 7HA.02 ACC	
State	City	ASHRAE Station	Alt (ft)	Ave T (F)	MW Adj SC	HR Adj SC	MW Adj CC	HR Adj CC	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net
ISO	ISO	-	0	59.0	100.0%	100.0%	100.0%	100.0%	105.1	8,220	232.6	8,923	418.3	5,793	406.9	5,955	1,083.3	5,739	1,026.5	6,056
Alabama	Huntsville	723230	624	61.7	96.8%	100.3%	97.2%	100.3%	101.7	8,242	225.1	8,947	406.4	5,809	395.3	5,971	1,052.5	5,754	997.4	6,072
Alaska	Anchorage	997381	10	37.4	108.6%	97.8%	105.4%	98.9%	114.1	8,042	252.6	8,730	440.7	5,731	428.7	5,891	1,141.4	5,677	1,081.6	5,991
Alaska	Fairbanks	702610	432	28.0	110.7%	96.9%	106.1%	98.5%	116.3	7,965	257.5	8,646	443.9	5,709	431.8	5,868	1,149.6	5,655	1,089.4	5,967
Arizona	Phoenix	722780	1,107	75.2	89.9%	101.6%	92.2%	101.0%	94.5	8,353	209.1	9,068	385.8	5,853	375.3	6,017	999.1	5,798	946.8	6,118
Arkansas	Little Rock	723400	563	61.6	97.0%	100.3%	97.4%	100.2%	101.9	8,241	225.7	8,946	407.4	5,808	396.3	5,970	1,055.0	5,753	999.8	6,071
California	Los Angeles	722950	97	63.2	98.0%	100.4%	98.6%	100.2%	103.0	8,254	227.9	8,961	412.5	5,807	401.3	5,969	1,068.3	5,752	1,012.3	6,070
California	Redding	725920	497	62.8	96.8%	100.4%	97.3%	100.3%	101.7	8,251	225.1	8,957	407.1	5,810	396.0	5,973	1,054.3	5,755	999.1	6,073
California	Bakersfield	723840	489	65.7	95.7%	100.7%	96.6%	100.4%	100.5	8,275	222.5	8,983	404.2	5,819	393.2	5,981	1,046.9	5,764	992.1	6,082
California	Modesto	724926	73	63.0	98.1%	100.4%	98.7%	100.2%	103.1	8,253	228.3	8,959	413.0	5,806	401.8	5,968	1,069.7	5,751	1,013.7	6,069
California	Sacramento	724839	23	61.9	98.8%	100.3%	99.2%	100.1%	103.8	8,244	229.7	8,949	414.9	5,802	403.6	5,964	1,074.6	5,747	1,018.3	6,065
California	San Francisco	724940	8	58.1	100.3%	99.9%	100.2%	100.0%	105.4	8,212	233.4	8,915	419.1	5,791	407.7	5,953	1,085.4	5,736	1,028.6	6,053
Colorado	Denver	725650	5,414	51.0	83.6%	99.2%	82.7%	100.7%	87.9	8,154	194.6	8,852	345.8	5,833	336.4	5,996	895.6	5,778	848.7	6,097
Connecticut	Hartford	725087	19	52.3	102.6%	99.3%	101.6%	99.7%	107.8	8,165	238.7	8,863	425.0	5,774	413.4	5,936	1,100.7	5,720	1,043.0	6,036
DC	Washington	745940	282	56.4	100.0%	99.7%	99.7%	99.9%	105.1	8,199	232.7	8,900	416.8	5,789	405.5	5,951	1,079.6	5,735	1,023.0	6,051
Delaware	Dover	724088	28	56.1	101.1%	99.7%	100.6%	99.9%	106.2	8,196	235.1	8,897	420.9	5,785	409.4	5,947	1,090.1	5,731	1,033.0	6,047
Florida	Tallahassee	722140	55	68.2	96.1%	100.9%	97.5%	100.5%	101.0	8,295	223.6	9,005	407.9	5,821	396.8	5,983	1,056.3	5,766	1,001.0	6,084
Florida	Tampa	722110	19	73.5	94.1%	101.5%	96.3%	100.7%	98.9	8,339	219.0	9,052	402.8	5,836	391.9	5,999	1,043.3	5,781	988.7	6,100
Georgia	Atlanta	722190	1,027	63.0	94.9%	100.4%	95.4%	100.4%	99.7	8,253	220.7	8,959	399.2	5,817	388.3	5,980	1,033.9	5,762	979.8	6,080
Hawaii	Honolulu	911820	7	77.8	92.5%	101.9%	95.3%	100.9%	97.2	8,374	215.1	9,091	398.5	5,848	387.7	6,012	1,032.1	5,793	978.1	6,113
Idaho	Boise	726810	2,814	52.9	92.4%	99.4%	91.5%	100.3%	97.0	8,170	214.8	8,869	382.8	5,808	372.4	5,971	991.5	5,753	939.6	6,071
Illinois	Chicago	997338	663	50.0	101.2%	99.1%	99.9%	99.7%	106.3	8,146	235.4	8,843	417.8	5,775	406.4	5,937	1,081.9	5,720	1,025.3	6,037
Indiana	Indianapolis	724380	790	53.6	99.3%	99.5%	98.5%	99.9%	104.4	8,175	231.1	8,875	412.2	5,787	401.0	5,949	1,067.5	5,732	1,011.6	6,049
Iowa	Davenport	725349	753	49.7	101.0%	99.1%	99.6%	99.7%	106.1	8,143	234.9	8,840	416.7	5,775	405.4	5,937	1,079.2	5,721	1,022.7	6,037
Iowa	Waterloo	725480	686	47.9	101.9%	98.9%	100.3%	99.6%	107.1	8,129	237.1	8,824	419.6	5,769	408.1	5,931	1,086.6	5,715	1,029.7	6,030
Kansas	Wichita	724500	1,321	57.6	95.9%	99.9%	95.7%	100.2%	100.8	8,208	223.1	8,911	400.3	5,805	389.4	5,967	1,036.8	5,750	982.5	6,068
Kentucky	Louisville	724230	488	58.3	98.6%	99.9%	98.5%	100.1%	103.6	8,214	229.3	8,917	411.8	5,797	400.6	5,959	1,066.6	5,742	1,010.8	6,060
Louisiana	New Orleans	722316	2	68.7	96.1%	101.0%	97.6%	100.5%	101.0	8,300	223.6	9,010	408.1	5,822	397.0	5,984	1,056.9	5,767	1,001.6	6,085
Maine	Portland	726060	45	47.1	104.6%	98.8%	102.8%	99.4%	109.9	8,122	243.3	8,817	430.0	5,760	418.3	5,921	1,113.7	5,705	1,055.4	6,020
Maryland	Baltimore	724060	56	56.0	101.0%	99.7%	100.6%	99.9%	106.1	8,195	234.9	8,896	420.6	5,785	409.1	5,947	1,089.3	5,731	1,032.2	6,047
Massachusetts	Boston	725090	12	52.0	102.8%	99.3%	101.7%	99.7%	108.0	8,162	239.0	8,861	425.4	5,773	413.8	5,935	1,101.8	5,719	1,044.1	6,035
Michigan	Detroit	725375	626	51.0	100.9%	99.2%	99.8%	99.7%	106.1	8,154	234.8	8,852	417.3	5,778	405.9	5,939	1,080.7	5,723	1,024.1	6,039
Michigan	Grand Rapids	726350	803	48.9	101.1%	99.0%	99.6%	99.7%	106.3	8,137	235.2	8,833	416.8	5,773	405.4	5,935	1,079.4	5,719	1,022.9	6,035
Minnesota	Saint Paul	726584	700	46.6	102.4%	98.8%	100.6%	99.5%	107.6	8,118	238.2	8,812	420.7	5,766	409.2	5,927	1,089.5	5,711	1,032.4	6,027
Mississippi	Jackson	722350	330	65.1	96.4%	100.6%	97.3%	100.4%	101.3	8,270	224.3	8,977	407.1	5,815	396.1	5,978	1,054.4	5,760	999.2	6,078
Missouri	St. Louis	724340	531	57.5	98.7%	99.9%	98.5%	100.0%	103.8	8,208	229.7	8,910	412.0	5,795	400.8	5,957	1,067.1	5,741	1,011.2	6,058
Missouri	Kansas City	724463	742	57.0	98.2%	99.8%	97.9%	100.0%	103.2	8,203	228.4	8,905	409.4	5,796	398.3	5,958	1,060.4	5,742	1,004.9	6,059
Montana	Great Falls	727750	3,364	45.2	93.1%	98.6%	91.3%	100.0%	97.8	8,106	216.6	8,800	381.8	5,792	371.4	5,954	988.7	5,737	936.9	6,055
Nebraska	Omaha	725530	1,332	51.6	98.2%	99.3%	97.1%	99.9%	103.2	8,159	228.3	8,857	406.1	5,787	395.1	5,949	1,051.9	5,733	996.8	6,050
Nevada	Las Vegas	724846	2,203	69.1	88.6%	101.0%	90.0%	100.9%	93.1	8,303	206.0	9,013	376.3	5,848	366.0	6,012	974.5	5,793	923.5	6,113
New Hampshire	Concord	726050	346	47.0	103.5%	98.8%	101.8%	99.5%	108.8	8,121	240.8	8,816	425.6	5,763	414.0	5,924	1,102.3	5,708	1,044.5	6,024
New Jersey	Newark	725020	7	55.8	101.3%	99.7%	100.8%	99.8%	106.4	8,194	235.5	8,894	421.5	5,784	410.0	5,946	1,091.7	5,730	1,034.5	6,046
New Mexico	Albuquerque	723650	5,310	58.1	81.7%	99.9%	81.6%	101.0%	85.9	8,212	190.1	8,915	341.3	5,852	332.0	6,016	883.9	5,797	837.6	6,117
New York	New York	725053	130	55.3	101.0%	99.6%	100.5%	99.8%	106.2	8,189	235.0	8,890	420.2	5,784	408.8	5,946	1,088.3	5,730	1,031.3	6,046
New York	Syracuse	725190	413	48.9	102.5%	99.0%	101.0%	99.6%	107.8	8,137	238.5	8,833	422.6	5,769	411.1	5,930	1,094.6	5,714	1,037.3	6,030
North Carolina	Asheville	723150	2,117	56.2	93.6%	99.7%	93.2%	100.3%	98.4	8,197	217.8	8,898	390.0	5,810	379.4	5,972	1,010.0	5,755	957.1	6,073
North Carolina	Charlotte	723140	728	61.3	96.6%	100.2%	96.9%	100.3%	101.5	8,239	224.6	8,944	405.3	5,809	394.2	5,971	1,049.6	5,754	994.6	6,072
North Dakota	Bismarck	727640	1,651	43.3	100.1%	98.4%	97.9%	99.5%	105.2	8,091	232.9	8,783	409.6	5,767	398.4	5,928	1,060.7	5,712	1,005.2	6,028
Ohio	Cincinnati	724297	490	55.0	99.9%	99.6%	99.3%	99.9%	104.9	8,187	232.3	8,887	415.2	5,788	403.9	5,949	1,075.3	5,733	1,019.0	6,050
Oklahoma	Oklahoma City	723530	1,285	61.2	94.7%	100.2%	95.0%	100.4%	99.5	8,238	220.2	8,943	397.3	5,815	386.5	5,977	1,028.9	5,760	975.0	6,078
Oklahoma	Tulsa	723560	650	61.3	96.8%	100.2%	97.2%	100.2%	101.8	8,239	225.2	8,944	406.4	5,808	395.3	5,970	1,052.5	5,753	997.4	6,071
Oregon	Portland	726980	19	54.6	101.7%	99.6%	101.0%	99.8%	106.9	8,184	236.6	8,884	422.6	5,781	411.1	5,943	1,094.5	5,726	1,037.2	6,043
Pennsylvania	Philadelphia	724080	10	56.6	100.9%	99.8%	100.6%	99.9%	106.1	8,200	234.8	8,902	420.6	5,787	409.2	5,948	1,089.4	5,732	1,032.3	6,049
Pennsylvania	Wilkes-Barre	725130	930	50.3	100.1%	99.1%	98.8%	99.8%	105.2	8,148	232.9	8,845	413.5	5,779	402.2	5,941	1,070.8	5,724	1,014.7	6,041
Puerto Rico	San Juan	994043	16	80.3	91.4%	102.1%	94.6%	101.1%	96.1	8,395	212.7	9,113	395.8	5,855	385.0	6,019	1,025.0	5,800	971.3	6,121
Rhode Island	Providence	997278	33	53.0	102.3%	99.4%	101.4%	99.7%	107.5	8,171	237.9	8,870	424.1	5,776	412.5	5,938	1,098.3	5,722	1,040.7	6,038
South Carolina	Charleston	722080	40	66.5	96.9%	100.8%	98.0%	100.4%	101.8	8,282	225.3	8,990	409.9	5,816	398.7	5,978	1,061.5	5,761	1,005.9	6,079
South Carolina	Spartanburg	723120	943	61.2	95.8%	100.2%	96.2%	100.3%	100.7	8,238	223.0	8,943	402.2	5,811	391.3	5,973	1,041.8	5,756	987.2	6,074
South Dakota	Rapid City	726620	3,160	47.4	93.1%	98.8%	91.5%	100.0%	97.8	8,125	216.5	8,820	382.8	5,796	372.4	5,958	991.4	5,742	939.5	6,059
Tennessee	Knoxville	723260	962	59.5	96.4%	100.1%	96.5%	100.2%	101.3	8,224	224.3	8,928	403.7	5,806	392.7	5,968	1,045.5	5,751	990.7	6,069
Tennessee	Nashville	723270	600	60.2	97.4%	100.1%	97.6%	100.2%	102.4	8,230	226.6	8,934	408.3	5,804	397.2	5,966	1,057.3	5,749	1,002.0	6,067
Texas	Houston	722436	32	70.6	95.3%	101.2%	97.0%	100.6%	100.1	8,315	221.6	9,027	405.7	5,827	394.6	5,990	1,050.7	5,772	995.7	6,091
Utah	Salt Lake City	725720	4,225	53.5	87.1%	99.5%	86.4%	100.6%	91.5	8,175	202.6	8,874	361.3	5,826	351.5	5,989	935.8	5,771	886.8	6,090

Gas Turbine Based Capacity and Heat Rate Adjustments

LOCATION		Adjustment Basis			Simple Cycle		Combined Cyle		2 x LM6000PF+		1 x 7F.05		1 x 7HA.01 WCT		1 x 7HA.01 ACC		2 x 7HA.02 WCT		2 x 7HA.02 ACC	
State	City	ASHRAE Station	Alt (ft)	Ave T (F)	MW Adj SC	HR Adj SC	MW Adj CC	HR Adj CC	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net	MW Net	HR Net
Vermont	Burlington	726170	330	46.6	103.7%	98.8%	101.9%	99.4%	109.0	8,118	241.3	8,812	426.3	5,761	414.7	5,922	1,104.0	5,707	1,046.1	6,022
Virginia	Alexandria	724050	10	58.7	100.1%	100.0%	100.0%	100.0%	105.2	8,217	232.8	8,920	418.4	5,793	407.1	5,955	1,083.7	5,738	1,027.0	6,055
Virginia	Lynchburg	724100	940	56.6	97.6%	99.8%	97.3%	100.1%	102.6	8,200	227.1	8,902	406.9	5,797	395.9	5,959	1,053.9	5,743	998.7	6,060
Washington	Seattle	994014	7	53.2	102.3%	99.4%	101.4%	99.7%	107.5	8,172	238.0	8,871	424.2	5,777	412.7	5,938	1,098.7	5,722	1,041.2	6,038
Washington	Spokane	727850	2,353	48.1	95.8%	98.9%	94.3%	99.9%	100.6	8,130	222.8	8,826	394.3	5,789	383.6	5,951	1,021.1	5,734	967.7	6,051
West Virginia	Charleston	724140	910	55.9	98.0%	99.7%	97.6%	100.0%	103.0	8,194	228.0	8,895	408.1	5,795	397.0	5,957	1,056.9	5,740	1,001.6	6,057
Wisconsin	Green Bay	726450	687	45.5	102.9%	98.7%	100.9%	99.5%	108.1	8,109	239.3	8,803	422.0	5,762	410.5	5,923	1,092.9	5,708	1,035.7	6,023
Wyoming	Cheyenne	725640	6,130	46.6	82.4%	98.8%	81.0%	100.6%	86.6	8,118	191.8	8,812	338.7	5,828	329.5	5,991	877.2	5,773	831.3	6,092

Kentucky Power Company
KPSC Case No. 2023-00092
Commission Staff's Post-Hearing Data Requests
Dated June 14, 2024

DATA REQUEST

KPSC PHDR_3	Refer to the table titled Preferred Plan Under Reference Scenario, on page 240 of 1182 of the IRP. Provide a monthly break down of the amounts in the Energy Surplus column for each year.

RESPONSE

Please see file KPCO_R_AG_KIUC_2_13_ConfidentialAttachment1, tab “Part A_B_D”.

Witness: Tomasz J. Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
Commission Staff's Post-Hearing Data Requests
Dated June 14, 2024

DATA REQUEST

KPSC PHDR_4	Provide blank copies of all matrixes, rubrics, scoring cards, or other assessment criteria used to grade the responses received for each of Kentucky Power's all source RFPs, including any such documents used to determine the "best in breed," as that phrase was used at the June 12, 2024 hearing, and any such documents used to assess different types of resources against each other.

RESPONSE

Please refer to KPCO_R_KPSC_PHDR_4_ConfidentialAttachment1 for the requested unpopulated scoring evaluation matrix. This matrix aggregates input information from the bids and various scoring component evaluations and other sources to develop the final scoring of each project. The projects are grouped first by resource technology type, for example wind, solar, storage, etc., to identify the highest rank projects specific to a resource type (i.e., "best in breed") and then all projects are combined in the summary to rank all projects regardless of technology type. Please also see KPCO_R_KPSC_PHDR__4_ConfidentialAttachment2 for economic scoring which "feeds" KPCO_R_KPSC_PHDR_4_ConfidentialAttachment1.

Witness: Alex E. Vaughan

KPCO_R_KPSC_PHDR_4_ConfidentialAttachment1 has been redacted in its entirety

KPCO_R_KPSC_PHDR_4_ConfidentialAttachment2 has been redacted in its entirety

Haratym Verification Form.doc

DocVerify ID:	89BE57D7-290B-4285-B709-B8EEB381A3A2
Created:	June 20, 2024 09:20:29 -8:00
Pages:	1
Remote Notary:	Yes / State: KY

E-Signature Summary

E-Signature 1: Tomasz Haratym (TH)
June 20, 2024 11:33:05 -8:00 [A8FBC845CD9F] [38.122.101.202]
THaratym@crai.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
June 20, 2024 11:33:05 -8:00 [08D0490294AB] [167.239.221.103]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Tomasz J. Haratym, being duly sworn, deposes and says he is the Associate Principal, for Charles River Associates, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief..

Tomasz Haratym

Tomasz J. Haratym

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tomasz J. Haratym, on June 20, 2024.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission# KYNP71841
My Commission Expires May 05, 2027

My Commission Expires May 5, 2027 Notarial act performed by audio-visual communication

Notary ID Number KYNP71841

Soller Verification Form rev1.doc

DocVerify ID:	CDB758A3-2309-4520-8E30-D538186763AA
Created:	June 24, 2024 12:49:26 -8:00
Pages:	1
Remote Notary:	Yes/ State: KY

E-Signature Summary

E-Signature 1: Gregory Soller (GS)
June 25, 2024 10:22:37 -8:00 [FCDD616469F3][167.239.221.101]
gsoller@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
June 25, 2024 10:22:37 -8:00 [A03C2E51F082] [167.239.221.102]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Gregory J. Soller, being duly sworn, deposes and says he is the Resource Planning Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Gregory Soller

Gregory J. Soller

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory J. Soller, on ____________.

Marilyn Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires ____________

Notary ID Number ____________

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief..

Alex E. Vaughan

______________)
______________) Case No. 2023-00092
______________)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 6/27/24.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03R.C.

My Commission Expires Never

Notary ID Number No ID

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is trueandcorrecttothebestofhisinformation, kno wledge, and belief.

Brian K. West

Commonwealth of Kentucky	)	
	)	Case No. 2023-00092
County of Boyd	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on June 24, 2024.

Marilyn Michelle Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841