FERC rendition of the electronically filed tariff records in Docket No. ER20- -000

Filing Data:
CID: C000038
Filing Title: Amended & Restated Interconnection Agreement (SA 2484) between RGE and RED-Rochester
Company Filing Identifier: 1523
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: NYISO Agreements
Tariff ID: 58
Payment Confirmation: N
Suspension Motion:

Tariff Record Data:
Record Content Description: Agreement No. 2484
Tariff Record Title: RGE & RED-Rochester Agreement
Record Version Number: 0.0.0
Option Code: A
Tariff Record ID: 249
Tariff Record Collation Value: 8085500
Tariff Record Parent Identifier: 2
Proposed Date: 2019-09-16
Priority Order: 500
Record Change Type: New
Record Content Type: 2
Associated Filing Identifier:

CUI//CEII – REDACTED VERSION

CUI//CEII – REDACTED VERSION

Service Agreement No. 2484

AMENDED AND RESTATED

INTERCONNECTION AGREEMENT

By and Between

ROCHESTER GAS AND ELECTRIC

CORPORATION

And

RED-ROCHESTER, LLC

Dated as of September 16, 2019

TABLE OF CONTENTS

Page

ARTICLE 1: DEFINITIONS 8

ARTICLE 2: TERM 16

2.1 Term 16

2.2 Extensions 16

2.3 Termination 17

2.4 Regulatory Approval. 17

2.5 Change of Law. 17

2.6 Continuing Obligation. 18

ARTICLE 3: CONTINUING OBLIGATIONS AND RESPONSIBILITIES 18

3.1 Provision of Service. 18

3.2 No Transmission Delivery Service. 18

3.3 No Other Services 19

3.4 Interconnection Service 19

3.5 Licenses, Easements, and Rights-of-Way 20

3.6 Facility and Equipment Maintenance 22

3.7 Equipment Testing Obligations 23

3.8 New Construction or Modifications 26

3.9 Inspections. 31

3.10 Information Reporting Obligations 31

3.11 Revenue Metering 34

3.12 Remote Terminal Units 35

3.13 Emergency Procedure 37

3.14 Interconnection Service Interruptions 38
3.15 Scheduled Maintenance Notification and Coordination 39
3.16 Safety..40
3.17 Electric Switching and Tagging Applications and Rules......................................42
ARTICLE 4: OPERATIONS..42
4.1 General. 42
4.2 Customer's Operating Obligations..43
4.3 Voltage or Reactive Control Requirements 44
4.4 Auditing of Accounts and Records 45
ARTICLE 5: COST RESPONSIBILITIES AND BILLING PROCEDURES 46
5.1 Cost Responsibilities for Interconnection Service 46
5.2 Cost Responsibilities for Services..48
5.3 Billing Procedures. 49
5.4 Interest on Unpaid Balances..49
5.5 Billing Disputes: Acceptance of Partial Payments.................................49
ARTICLE 6: DOCUMENTATION 50
6.1 Drawings 50
ARTICLE 7: CONFIDENTIALITY 50
7.1 Confidentiality of RGE 50
7.2 Confidentiality of Customer..51
7.3 Confidentiality of Audits...52
7.4 Remedies 52
7.5 Disclosure to FERC, its Staff, or a State 52
ARTICLE 8: EVENTS OF DEFAULT 53
8.1 Events of Default...53

8.2 Notice, Cure, and Remedies 54

8.3 Right to Take Immediate Action 55

ARTICLE 9: INDEMNIFICATION 55

9.1 Customer's Indemnification 55

9.2 RGE's Indemnification 56

9.3 Indemnification Procedures 56

9.4 Survival 57

ARTICLE 10: INSURANCE 57

10.1 Maintenance of Insurance Coverages 57

10.2 Certificates of Insurance 57

10.3 Notice Requirements 58

10.4 Additional Insureds 58

10.5 Contents of Certificates of Insurances 58

10.6 Insurer Requirements 59

10.7 Endorsements 59

10.8 Self-Insurance 59

10.9 Subcontractor Insurance Requirements 59

ARTICLE 11: FORCE MAJEURE 59

11.1 Definition 59

11.2 Economic Hardship 60

11.3 Requirements 60

11.4 Continuing Obligations 60

11.5 Written Notice 61

ARTICLE 12: DISPUTES 61

12.1 Initial Procedures....61

12.2 External Arbitration Procedures....62

12.3 Arbitration Decisions....63

12.4 Costs....64

ARTICLE 13: REPRESENTATIONS....65

13.1 Representation of RGE....65

13.1.1 Organization....65

13.1.2 Authority Relative to this Agreement....65

13.1.3 Regulatory Approval....65

13.1.4 Compliance With Law....65

13.2 Representations of Customer....66

13.2.1 Organization....66

13.2.2 Authority Relative to this Agreement....66

13.2.3 Regulatory Approval....66

13.2.4 Compliance with Law....67

13.3 Representation of Both Parties....67

ARTICLE 14: ASSIGNMENT/CHANGE IN CORPORATE IDENTITY....67

14.1 Successors and Assigns....67

14.2 Continuation of Liability and Responsibility....68

14.3 Protection of Rights....68

ARTICLE 15: SUBCONTRACTORS....69

15.1 Use of Subcontractors Permitted....69

15.2 Continuing Obligations of Parties....69

ARTICLE 16: LABOR RELATIONS....69

ARTICLE 17: INDEPENDENT CONTRACTOR STATUS....70

ARTICLE 18: LIMITATIONS OF LIABILITY 70
ARTICLE 19: NOTICES 70
19.1 Contact Person 70
19.2 Written Notice 71
19.3 Notice to NYISO 72
19.4 Emergencies 72
ARTICLE 20: HEADINGS AND RULES OF INTERPRETATION 72
20.1 Headings 72
20.2 Construction 72
ARTICLE 21: WAIVER 73
21.1 General 73
21.2 No Waiver of Capacity and Energy Service Rights 73
21.3 Writing 74
ARTICLE 22: COUNTERPARTS 74
ARTICLE 23: GOVERNING LAW 74
23.1 General 74
23.2 New York Law 74
23.3 PURPA Status 74
23.4 Filing of Agreement 75
23.5 Reservation of Rights 75
ARTICLE 24: SEVERABILITY 75
ARTICLE 25: AMENDMENT 75
ARTICLE 26: ENTIRE AGREEMENT 76
26.1 Entire Understanding 76

26.2 Conflicts 76

26.3 Joint and Several Obligations..76

ARTICLE 27: NO THIRD PARTY BENEFICIARIES 76

ARTICLE 28: FURTHER ASSURANCES 76

Schedule A: RGE and Customer Interconnection Facilities and Associated Equipment

Schedule B: Insurance Requirements

Schedule C: Customer's Costs and Expenses for RGE Interconnection Service

Schedule D: One-Line Electrical Diagrams

Schedule E: NYSEG/RGE Bulletin 86-01

Schedule F: Electric Switching and Tagging Applications and Rules

Schedule G: Metering Equipment Description

Schedule H: RTU Data Points

Schedule I: Data Reporting

Schedule J: Joint Use Facilities

INTERCONNECTION AGREEMENT

This Amended and Restated Interconnection Agreement ("Agreement") dated as of September 16, 2019, by and between Rochester Gas and Electric Corporation ("RGE"), a New York corporation with an office for the transaction of business in Rochester, New York, and RED-Rochester, LLC ("Customer"), a New York limited liability company with an office for the transaction of business in Rochester, New York. RGE and Customer shall each be considered a "Party" and, collectively, they shall be referred to as the "Parties."

WITNESSETH:

WHEREAS, RGE and Eastman Kodak Company, a New Jersey corporation ("Kodak") entered into an interconnection agreement on March 16, 2006; and

WHEREAS, Kodak sold the Eastman Business Park Utility Business to Customer on August 31, 2013 ("Transaction"): and

WHEREAS, as part of the Transaction, the interconnection agreement was assigned to Customer on August 31, 2013; and

WHEREAS, RGE is a corporation organized under the New York Transportation Corporations Law, is authorized by its Restated Certificate of Incorporation and by the State of New York to engage in the production, transmission, sale and distribution of electricity for heat, light and power to the public, and is an "electric corporation" as defined in Section 2, subdivision 13, of the New York Public Service Law; and

WHEREAS, Customer is a limited liability company organized under the laws of the State of New York, and owns, operates, and maintains electric generating equipment and appurtenant facilities, including Customer Interconnection Facilities (as defined in Section 1.4

below) and Joint Use Facilities (as defined in Section 1.13 below) at Eastman Business Park in Monroe County, New York; and

WHEREAS, the NYISO operates the Transmission System and RGE owns certain facilities included in the Transmission System;

WHEREAS, the Plant constitutes a "qualifying facility" under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and its related regulations; and

WHEREAS, the Parties have agreed to execute this mutually acceptable Agreement in order for the purpose of interconnecting Customer's electric generating facilities to the Transmission System defining the continuing responsibilities and obligations of the Parties;

NOW THEREFORE, in order to carry out the transactions contemplated in this Agreement, and in consideration of the mutual representations, covenants and agreements hereinafter set forth, and intending to be legally bound hereby, the Parties hereto agree as follows:

ARTICLE 1
DEFINITIONS

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article 1. Terms used in this Agreement that are not defined herein will have the meanings customarily attributed to such terms by the electric utility industry in New York.

1.1 "Affiliate" shall mean, with respect to a corporation, partnership, or other entity, each other corporation, partnership, or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership, or other entity. The term "control" shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

1.2 “Agreement” shall mean this Amended and Restated Interconnection Agreement dated as of September 16, 2019 by and between RGE and Customer, including all schedules attached hereto and any amendments hereto.

1.3 “Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to load while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

1.4 “Capacity Resource Interconnection Service” shall mean the service provided by NYISO to generation developers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive such service in accordance with Attachment S to the OATT; such service being one of the eligibility requirements for participation as a NYISO installed capacity supplier.

1.5 “Customer” shall mean RED-Rochester, LLC, and its successor.

1.6 “Customer Interconnection Facilities” shall mean all structures, facilities, equipment, devices, and apparatus at or connected to RGE’s substations 403 and 412, which are identified as Customer Interconnection Facilities and Associated Equipment in Schedule D, as the same may be amended from time to time by a writing signed by the Parties, which facilities are owned, operated or leased by Customer and are necessary to facilitate the interconnection of the Plant to the Transmission System.

1.7 “EBP” shall mean the Eastman Business Park located in Monroe County, New York.

1.8 "Effective Date" shall mean the date on which this Agreement becomes effective upon execution by the Parties, subject to acceptance by the FERC, or if filed unexecuted, upon the date specified by the FERC.

1.9 "Electric Switching and Tagging Applications and Rules" shall mean the Avangrid Network Energy Control Center Switching and Tagging Rules and Procedures, as amended or superseded, which apply to RGE. A current copy of the Electric Switching and Tagging Applications and Rules is attached to this Agreement as Schedule F.

1.10 "Emergency" shall mean (a) with respect to RGE, a condition or situation which RGE or the NYISO deems immediately likely to (i) endanger life or property, or (ii) adversely affect or impair the Transmission System, RGE's electrical systems or the electrical or transmission systems of others to which the Transmission System or RGE's electrical system are directly or indirectly connected, which requires, in accordance with Good Utility Practice, that the output of the Plant over the Interconnection Facilities be adjusted to avoid or mitigate such condition or situation, and (b) with respect to Customer, a condition or situation which Customer deems imminently likely to (i) endanger life or property, or (ii) adversely affect or impair the Plant. Such a condition or situation includes, but is not limited to, overloading or potential overloading, excessive voltage drop or unusual operation conditions beyond the rated capacity of existing equipment of the Plant.

1.11 "Energy Resource Interconnection Service" shall mean the service provided by NYISO to interconnect generation owners' generating facilities to the Transmission System in accordance with the NYISO Minimum Interconnection Standard, to enable the Transmission System to receive energy and Ancillary Services from the generating facilities, pursuant to the terms of the OATT.

1.12 "FERC" shall mean the Federal Energy Regulatory Commission, or its successor or equivalent.

1.13 "Generating Meters" shall mean meters that are owned, installed, operated, tested and maintained by Customer and are individually located at the Plant such that they can provide gross MW quantities at each of the generator terminals. Generating Meters may be added to Schedule G, if deemed necessary. Generating Meters do not include Revenue Meters.

1.14 "Good Utility Practice" shall mean any of the applicable practices, methods, and acts:

a. required by NERC, NPCC, NYSRC, NYISO, FERC, NYPSC, OSHA, a regional transmission organization, or the successor of any of them, whether or not the Party whose conduct is at issue is a member thereof;

b. required by the policies and standards of RGE relating to Emergencies;

c. the NYSEG/RGE Bulletin 86-01 and the Electric Switching and Tagging Applications and Rules, provided however, that neither shall be considered Good Utility Practice as to Customer unless expressly stated otherwise in this Agreement; and

d. otherwise engaged in or approved by a significant portion of the electric generation, transmission, and distribution industry in the region during the relevant time period, or any of the practices, methods or acts which, in the exercise of Reasonable judgment in light of the facts known at the time the decision is made, could be expected to accomplish the desired result at a Reasonable cost consistent with law, regulation, 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 to practices, methods, or acts generally accepted by the electric generation, transmission, and distribution industry in the region.

1.15 “Host Load” shall mean the load (expressed in terms of energy or demand) that is within the EBP and routinely served by Customer via its electric generating facilities located at the EBP. Station Power is included in the calculation of Customer’s Host Load to the extent it is supplied by the electric generating facilities located at the EBP and provided that it is not separately metered pursuant to Section 5.12.6.1.1 of the Services Tariff and the procedures adopted by the NYISO in order to fulfill its responsibilities under the Services Tariff and the OATT.

1.16 “Interconnection Facilities” shall mean the Customer Interconnection Facilities and the RGE Interconnection Facilities, collectively.

1.17 “Interconnection Service” shall mean the service provided by the NYISO to interconnect the Plant with the Transmission System.

1.18 “Joint Tag List” shall mean the list of personnel approved from time to time by RGE in accordance with Good Utility Practice who meet RGE’s requirements to switch, tag, and ground electrical equipment.

1.19 “Joint Use Facilities” shall mean the facilities and equipment which are listed on Schedule J, which schedule may be modified from time to time upon the Parties’ mutual written agreement.

1.20 “Maintain” shall mean construct, reconstruct, install, inspect, repair, replace, operate, patrol, maintain, use, modernize, expand or upgrade, or undertake other similar activities.

1.21 "New York State Transmission System" shall mean the entire New York State electric transmission system, which includes (i) the transmission facilities under the NYISO's operational control; (ii) the transmission facilities requiring NYISO notification; and (iii) all remaining transmission facilities within the New York Control Area.

1.22 "New York Control Area" shall mean the electric system that is under the control of the NYISO which includes transmission facilities listed in Appendices A‑1 and A‑2 to the ISO/TO Agreement, as amended from time to time, electric generating facilities located within New York State, and electric generating facilities located outside New York State but which may, from time to time, be subject to the operational control of the NYISO.

1.23 "NYSEG" shall mean New York State Electric & Gas Corporation, and its successor.

1.24 "NYPSC" shall mean the New York State Public Service Commission, or its successor or equivalent.

1.25 "NERC" shall mean the North American Electric Reliability Corporation, or its successor or equivalent.

1.26 "NPCC" shall mean Northeast Power Coordinating Council, Inc., , or its successor or equivalent.

1.27 "NYISO" shall mean the New York Independent System Operator, Inc. or its successor or equivalent.

1.28 "NYISO Deliverability Interconnection Standard" shall mean the standard that must be met, unless otherwise provided for by Attachment S to the OATT, by (i) any generating facility larger than 2 MW in order for that facility to obtain Capacity Resource Interconnection Service; (ii) any class year transmission project; (iii) any entity requesting external Capacity Resource Interconnection Service rights, and (iv) any entity requesting a Capacity Resource Interconnection Service transfer pursuant to Section 25.9.5 of Attachment S to the OATT.

1.29 "NYISO Minimum Interconnection Standard" shall mean the reliability standard that must be met by any generating facility or class year transmission project that is subject to the NYISO's Large Facility Interconnection Procedures in Attachment X to the OATT or the NYISO's Small Generator Interconnection Procedures in Attachment Z to the OATT, that is proposing to connect to the Transmission System.

1.30 "NYSEG/RGE Bulletin 86-01" shall mean the NYSEG/RGE Bulletin 86-01, as amended or superseded. A current copy of NYSEG/RGE Bulletin 86-01 is attached hereto as Schedule E.

1.31 "NYSRC" shall mean the New York State Reliability Council, L.L.C., or its successor or equivalent.

1.32 "OATT" shall mean the NYISO's Open Access Transmission Tariff, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff.

1.33 "OSHA" shall mean the Occupational Safety and Health Administration, or its successor or equivalent.

1.34 "Party" or "Parties" shall mean RGE, Customer, or both RGE and Customer.

1.35 "Plant" shall mean the topping-cycle cogeneration facility, electric system, and turbine-generators owned by Customer and located at the EBP, and the Customer Interconnection Facilities and Joint Use Facilities owned by Customer.

1.36 "Points of Interconnection" shall mean the RGE disconnect switches at substation 412 and the separation of RGE's circuit breaker cubical and Customer's circuit breaker cubical at substation 403, which represent the points of demarcation between RGE's electric system and Customer's electric system and where capacity, energy, and ancillary services are transferred between the Plant and the Transmission System. The Points of Interconnection are shown in Schedule D to this Agreement.

1.37 "Reasonable" and "Reasonably" shall mean (i) with respect to an action required to be attempted or taken by a Party, under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests; and (ii) with respect to costs under this Agreement, costs that are consistent with the exercise of Good Utility Practice and are otherwise are substantially equivalent to those a Party would incur on its own behalf for a similar purpose or to protect its own interests.

1.38 "RGE" shall mean Rochester Gas and Electric Corporation, and its successor.

1.39 "RGE Interconnection Facilities" shall mean all structures, facilities, equipment, devices, and apparatus at or connected to RGE's substations 403 and 412, as which are identified as RGE Interconnection Facilities and Associated Equipment in Schedule D, as the same may be amended from time to time by a writing signed by the Parties, which facilities are owned, operated or leased by RGE and are necessary to facilitate the interconnection of the Plant to the Transmission System.

1.40 "Revenue Meters" shall mean all kWh meters, kVAR meters, pulse isolation relays, pulse conversion relays, or transducers used by RGE for billing purposes, located on the RGE 34 kV bus at substation 412 and on the RGE 11.5 kV bus at substation 403, and associated totalizing equipment and appurtenances (including voltage transformers and current transformers) used to measure the sales of capacity, energy or ancillary services into the

NYISO's wholesale markets. A description of the metering is included in this Agreement in Schedule G. Revenue Meters shall not include Generating Meters.

1.41 "Services Tariff" shall mean the NYISO's Market Administration and Control Area Services Tariff, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff.

1.42 "Transmission System" shall mean the portion of the New York State Transmission System owned by RGE, which includes (i) RGE's transmission facilities under the NYISO's operational control; (ii) RGE's transmission facilities requiring NYISO notification; and (iii) all remaining RGE transmission facilities within the New York Control Area.

ARTICLE 2
TERM

2.1 Term. Except as provided herein, this Agreement shall become effective as of the Effective Date, on which date the interim interconnection agreement between the Parties, as reflected in the letter agreement of April 25, 2004, shall terminate, and this Agreement shall continue in full force and effect until September 15, 2029, unless sooner terminated in accordance with the terms hereof.

2.2 Extensions. Effective September 16, 2029, this Agreement shall be extended for additional five-year terms unless either Party objects to that extension by providing written notice of such objection to the other Party not less than twelve (12) calendar months prior to September 15, 2029 or any subsequent expiration date, as applicable. If such notice of objection is timely provided, this Agreement shall expire and be of no further force and effect as of September 15, 2029, or on any subsequent expiration date, as applicable.

2.3 Termination.. This Agreement may be terminated by mutual agreement of the Parties or otherwise in accordance with the terms of this Agreement. This Agreement also may be terminated at any time by Customer by giving RGE sixty (60) days' advance written notice.

2.4 Regulatory Approval. This Agreement is subject to any necessary FERC acceptance or approval without any material modification or condition. RGE shall file this Agreement with the FERC within thirty (30) days of the date it is executed by both Parties. If the FERC requires any modification to, or imposes any condition of acceptance or approval of, this Agreement, and such modification or condition could Reasonably be expected to create a material adverse effect on the business, assets, operations or conditions (financial or otherwise) of either Party, then the Parties shall engage in good-faith negotiations for a period of thirty (30) days following the issuance of that acceptance or approval in order to agree to revisions to this Agreement to satisfy, or otherwise address, such modification or condition. If the Parties fail to agree mutually to such changes, their dispute shall be resolved in accordance with Article 12.

2.5 Change of Law. If (a) the U.S. Congress, any other governmental agency having jurisdiction over the Parties, or the NYISO adopts a change in any law, regulation, rule or practice or (b) RGE complies with, and/or implements, a change in any law, regulation, rule or practice, which change or compliance affects, or may Reasonably be expected to affect, RGE's performance under this Agreement, then RGE and Customer shall negotiate in good faith any amendments to this Agreement that are necessary to adapt the terms of this Agreement to such change, and RGE shall file such amendments with the FERC. If the Parties are unable to reach agreement on such amendments within a Reasonable time, their dispute shall be resolved in accordance with Article 12.

2.6 Continuing Obligation. The applicable provisions of this Agreement shall continue in effect after expiration, cancellation or termination hereof to the extent necessary to provide for final billings, billing adjustment, and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this agreement was in effect.

ARTICLE 3
CONTINUING OBLIGATIONS AND RESPONSIBILITIES

3.1 Provision of Service. The Parties understand that the NYISO and RGE will provide Customer with Interconnection Service of the following type for the term of this Agreement.

3.1.1 Products. The Parties understand that the NYISO will provide Energy Resource Interconnection Service and Capacity Resource Interconnection Service to Customer.

3.1.2 RGE and the NYISO shall cause the Transmission System, RGE's Interconnection Facilities, and the Joint Use Facilities owned by RGE to be operated, Maintained and controlled in a safe and reliable manner in accordance with this Agreement, Good Utility Practice, and the Services Tariff and OATT.

3.1.3 Customer shall cause the Customer Interconnection Facilities and the Joint Use Facilities owned by Customer to be operated, Maintained and controlled in a safe and reliable manner in accordance with this Agreement, Good Utility Practice, and the Services Tariff and OATT.

3.2 No Transmission Delivery Service. The execution of this Agreement does not constitute a request for, nor agreement to provide, any Transmission Service under the Services Tariff or OATT, and does not convey any right to deliver electricity to any specific customer or point of delivery. If Customer wishes to obtain Transmission Service on the Transmission

System, then Customer must request such Transmission Service in accordance with the provisions of the Services Tariff and OATT.

3.3 No Other Services. The execution of this Agreement does not constitute a request for, nor agreement to sell or purchase, Energy, Ancillary Services, or Installed Capacity under the Services Tariff or OATT. If Customer wishes to sell Energy, Ancillary Services, and Installed Capacity into the NYISO's wholesale markets, Customer must make application to do so in accordance with the Services Tariff and OATT.

3.4 Interconnection Service.

3.4.1 RGE shall provide Customer with Interconnection Service over the RGE Interconnection Facilities at the Points of Interconnection under the terms and conditions specified in this Agreement. During the term of this Agreement, RGE shall maintain the rating of the RGE Interconnection Facilities that exists on the Effective Date; provided however, that if Customer reduces the rating of the Customer Interconnection Facilities that exist on the Effective Date other than for a temporary period of time, RGE shall be permitted to make a corresponding reduction to the rating of the RGE Interconnection Facilities. After such reduction, if Customer then seeks to increase the rating of the Customer Interconnection Facilities, Customer shall be responsible, in accordance with applicable tariffs or agreements (including, if applicable, Article 5 of this Agreement) for costs and expenses incurred by RGE in having to increase and maintain the rating of the RGE Interconnection Facilities to accommodate Customer's increase in rating. The RGE Interconnection Facilities necessary to interconnect the Plant to the Transmission System are set forth in Schedule A to this Agreement. Interconnection Service shall be provided under this Agreement only with respect to the Plant, and shall not include the interconnection of any other generating unit outside of the Plant, wherever located, to the Transmission System.

3.4.2 RGE does not guarantee the non-occurrence of, or warrant against, (a) any interruption in the availability of the RGE Interconnection Facilities or the Transmission System, or (b) damage to the Plant resulting from electrical transients, including short circuits (faults), or events of Force Majeure as defined in Article 11, except to the extent that such interruption or damage is caused by the gross negligence or willful misconduct of RGE. RGE's liability for damages under this Section 3.4.2 arise only in the event of its gross negligence or willful misconduct and shall be limited to the cost of the repair or replacement of Customer's damaged facilities and/or equipment.

3.5 Licenses, Easements, and Rights-of-Way.

3.5.1 General. The Points of Interconnection, and certain operational procedures and practices for the RGE Interconnection Facilities, are referenced in Schedules A and D to this Agreement. RGE shall have the right, upon written agreement with Customer, to revise Schedule A as necessary during the term of this Agreement.

3.5.2 Each Party (in this instance, the "Granting Party") will provide to the other Party ("Access Party"), upon the Access Party's Reasonable request and at no cost to the Access Party, such licenses, easements, and/or rights-of-way as the Access Party may require to exercise its rights and carry out its obligations under this Agreement and to Maintain the Transmission System, Interconnection Facilities, and/or Joint Use Facilities; provided, however, that the Granting Party's obligations under this Section 3.5.2 shall be limited to the grant or provision of only those licenses, easements, and/or rights-of-way as are necessary or required to support the Transmission System, Interconnection Facilities, and/or Joint Use

Facilities to the extent that it is used in relation to the provision of Interconnection Service to Customer or otherwise to satisfy a Party's obligations under this Agreement; and provided further that such access shall not unreasonably disrupt or interfere with the normal operations of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party. The Access Party shall indemnify the Granting Party against all claims of injury or damage from third parties resulting from the exercise of the access rights provided for herein.

3.5.3 The licenses, easements, and/or rights-of-way granted to either Party under this Section 3.5 will remain in effect for so long as the Interconnection Facilities remain in service. Such licenses, easements, and/or rights-of-way may not be revoked or terminated by the Granting Party during the term of this Agreement, and the Granting Party will not take any action that would impede, restrict, or diminish or otherwise interfere with any of the rights granted to the Access Party under this Section 3.5. The Access Party will, at its sole cost and expense execute such documents, as may Reasonably be required, to establish record evidence of such licenses, easements, and/or right-of-way, and such documents shall be recorded by the Access Party, at its sole cost and expense.

3.5.4 Notwithstanding the foregoing, should a Party decide to permanently abandon the use of any such license, easement, or right-of-way, or any portion of any of them, or if the Transmission System or Interconnection Facilities are removed from service, the Access Party will send the Granting Party written notice of such decision or event and the Access Party will cause a release of such license, easement, or right-of-way or portion thereof to be recorded at its sole cost and expense.

3.5.5 If any part of the Interconnection Facilities or Joint Use Facilities is, or is to be, installed on property owned by persons other than RGE or Customer, RGE shall at Customer's expense use efforts similar in nature and extent to those that it typically undertakes for its own facilities, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, and Maintain the Interconnection Facilities or Joint Use Facilities upon such property.

3.5.6 Notwithstanding any other provision of this Agreement to the contrary, the provisions of this Section 3.5 shall survive the expiration, cancellation or termination of this Agreement as long as Reasonably necessary so as to allow the Parties to dismantle and remove the Transmission System, Interconnection Facilities, and/or Joint Use Facilities, as applicable..

3.6 Facility and Equipment Maintenance.

3.6.1. Customer shall Maintain the Plant to the extent required by and in accordance with Good Utility Practice. RGE shall Maintain the Transmission System to the extent required by and in accordance with Good Utility Practice and all applicable laws, regulations, and governmental orders. Customer shall Maintain all common-use roadways and accesses over Customer-owned lands to the Transmission System facilities to the extent Reasonably required or necessary to provide Interconnection Service to Customer under this Agreement.

3.6.2 At its sole expense, Customer shall Maintain in full force and effect all permits, licenses, rights-of-way, and other authorizations as may be required to Maintain the Customer Interconnection Facilities.

3.6.3 At its sole expense, RGE shall Maintain in full force and effect all permits, licenses, rights-of-way, and other authorizations as may be required to Maintain the Transmission System and RGE Interconnection Facilities.

3.6.4 RGE and Customer shall Maintain in full force and effect all permits, licenses, rights-of-way, and other authorizations as may be required to Maintain the Joint Use Facilities and split the costs associated with doing so. Unless otherwise agreed between the Parties, RGE shall have primary responsibility to Maintain the Joint Use Facilities.

3.6.5 Customer shall be responsible to perform or to have performed routine inspections, maintenance, certifications, and tests on the Customer Interconnection Facilities in accordance with Good Utility Practice, including NYSEG/RGE Bulletin 86-01 and the Electric Switching and Tagging Applications and Rules, to the extent either is made applicable to Customer under this Agreement.

3.6.6 RGE shall be responsible to perform or have performed routine inspections, maintenance, certifications, and tests on the RGE Interconnection Facilities and Joint Use Facilities in accordance with Good Utility Practice, including the requirements specified in NYSEG/RGE Bulletin 86-01 and the Electric Switching and Tagging Applications and Rules.

3.7 Equipment Testing Obligations.

3.7.1 RGE may Reasonably request, upon 24 hours' notice and pursuant to Good Utility Practice that Customer test, calibrate, verify, or validate the generating equipment components of the Plant, the Customer Interconnection Facilities, and/or the Joint Use Facilities owned by Customer. Customer shall promptly comply with such a request. All such testing, calibrating, verifying, and validating shall be undertaken during Customer's normal business hours for the Plant, Monday through Friday, except for federal holidays, unless there is an Emergency. Customer shall be responsible for all Reasonable costs of testing, calibrating, verifying or validating requested by RGE pursuant to this Section 3.7.1.

3.7.2 Customer shall supply to RGE, at RGE's request, and at no cost to RGE, one copy of inspection reports, installation and maintenance documents, test and calibration records, verification, and validations related to the generating equipment components of the Plant, the Customer Interconnection Facilities, and the Joint Use Facilities owned by Customer.

3.7.3 Customer may Reasonably request, upon 24 hours' notice and pursuant to Good Utility Practice, that RGE test, calibrate, verify, or validate the RGE Interconnection Facilities and/or the Joint Use Facilities owned by RGE, and RGE shall promptly comply with such a request. All such testing, calibrating, verifying, and validating shall be undertaken during normal business hours, Monday through Friday, except for federal holidays, unless there is an Emergency. RGE shall be responsible for all Reasonable costs RGE incurred in complying with this Section 3.7.3.

3.7.4 RGE shall supply to Customer, at Customer's request, and at no cost to Customer, one copy of all inspection reports, installation and maintenance documents, test and calibration records, verifications, and validations related to the RGE Interconnection Facilities and the Joint Use Facilities owned by RGE.

3.7.5 Under normal operating circumstances, each Party shall provide advance verbal notice to the other Party of not less than 24-hours prior to undertaking work on the Joint Use Facilities. Each Party shall cooperate with the other in the inspection, maintenance, and testing of the Joint Use Facilities so that, among other operations, the Party conducting the inspection, maintenance or testing (a) shall be granted Reasonable access to the Joint Use Facilities; and (b) shall schedule such access to, and work on, the Joint Use Facilities so as not to interfere unreasonably with the activities of the other Party.

3.8 New Construction or Modifications.

3.8.1 Unless otherwise required by law, regulation, or Good Utility Practice, RGE shall not be required at any time to upgrade or otherwise modify the Transmission System or the RGE Interconnection Facilities.

3.8.2 Unless otherwise required by law, regulation, or Good Utility Practice, Customer shall not be required at any time to upgrade or otherwise modify the Customer Interconnection Facilities.

3.8.3 RGE may undertake additions, modifications, or replacements of the Transmission System or the RGE Interconnection Facilities. If such additions, modifications, or replacements might Reasonably be expected to affect, in RGE's Reasonable judgment, Customer's operation of the Plant, RGE shall provide Customer sixty (60) days prior written notice of the necessity of the additions, modifications, or replacements prior to undertaking such additions, modifications, or replacements. If RGE is required to submit a filing to the FERC regarding the necessity of the additions, modifications, or replacements, RGE shall provide Customer with a copy of all such filing(s) concurrent with the electronic submission of the filing to the FERC. If Customer notifies RGE within such sixty (60) day period that RGE's proposed additions, modifications, or replacements could Reasonably be expected, in Customer's Reasonable judgment, to have an adverse impact on Customer's operation of the Plant, then RGE shall use Reasonable efforts to examine a Reasonable alternative design to such addition, modification, or replacement to eliminate such adverse impact on Customer's operation of the Plant, and Customer shall provide to RGE such information and consultation Reasonably required to enable RGE to complete such examination. In no event shall RGE be obligated to undertake an alternative design that will result in materially greater costs to RGE than those costs that would have been incurred under the initial design. Any such additions, modifications, or replacements shall comply with Good Utility Practice and all applicable laws, regulations, and governments orders.

3.8.4 If Customer plans any addition, modification, retirement or replacement to the Plant or to the Customer Interconnection Facilities or otherwise plans a change to its mode of operation (a "Customer Project") that (a) will increase the capacity of the generating equipment components of the Plant, or (b) could Reasonably be expected, in RGE's Reasonable judgment, to affect the Transmission System or the RGE Interconnection Facilities, Customer shall submit sixty (60) days prior written notice briefly describing the proposed Customer Project to RGE and thereafter shall submit to RGE any and all data, information and documentation that RGE may Reasonably request related to such proposed Customer Project. Within sixty (60) days after RGE receives such data, information and documentation, RGE shall notify Customer of (a) any additions, modifications and/or replacements to the Transmission System ("Transmission System Improvements") or RGE Interconnection Facilities ("Interconnection Facilities Improvements") which would be necessitated by the Customer Project, (b) an initial estimate of the design, construction, and ongoing operating and maintenance costs for the Transmission System Improvements or Interconnection Facilities Improvements which would be payable by Customer pursuant to Sections 5.1 and 5.2, and (c) the length of time necessary to complete such Transmission System Improvements or Interconnection Facilities Improvements (and related tasks, approvals, and activities); provided, however, that should RGE determine that additional information is required, RGE shall notify Customer of the need for the additional information and RGE's sixty (60) day period for notifying Customer shall be tolled while RGE awaits receipt of such additional information. Any such Customer Project shall comply with Good Utility Practice. Any addition, modification, or replacement to the Customer Interconnection Facilities associated with any such Customer Project shall be subject to the review and acceptance of RGE, which review shall be based on Good Utility Practice, and which acceptance shall not unreasonably be withheld, conditioned, or delayed.

3.8.5 In accordance with Article 5, Customer shall reimburse RGE for: (a) all Reasonable costs and expenses described and permitted in Sections 5.1 and 5.2 which are incurred by RGE for the design, engineering, procurement, construction, installation, and any start up testing of any Transmission System Improvements or Interconnection Facilities Improvements, required as a result of a Customer Project, regardless of whether the Customer Project enters (or has entered into) service, or is interconnected with the Transmission System, (b) any Reasonable costs described and permitted in Section 5.2 which are incurred by RGE to operate and maintain such Transmission System Improvements or Interconnection Facilities Improvements; provided, however, that RGE shall not seek or be entitled to reimbursement of any such costs or expenses to the extent they are properly included or includable in RGE’s capital accounts or rate base for recovery from RGE’s ratepayers. RGE shall not undertake construction of the Transmission System Improvements or Interconnection Facilities Improvements until Customer provides written notice of its intent to proceed with the Customer Project.

3.8.6 RGE’s acceptance of Customer’s interconnection plans and specifications for any proposed additions, modifications or replacements of the generating equipment components of the Plant, the Customer Interconnection Facilities, and/or the Joint Use Facilities owned by Customer, and RGE’s participation in interconnected operations with

Customer, are not and shall not be construed as: (a) a confirmation or endorsement of the design of the generating equipment components of the Plant, the Customer Interconnection Facilities; and/or the Joint Use Facilities owned by Customer; (b) a warranty of the safety, durability or reliability of the generating equipment components of the Plant, the Customer Interconnection Facilities, and/or the Joint Use Facilities owned by Customer; or (c) creating responsibility of the strength, details of design, adequacy, or capability of the generating equipment components of the Plant, the Customer Interconnection Facilities, and/or the Joint use Facilities owned by Customer.

3.8.7 Notwithstanding anything to the contrary set forth herein, all work performed in connection with the construction, installation, and maintenance of additions, modifications, or replacements to the Plant that requires the performance of any activities that may physically affect, in Customer's Reasonable judgment, the Transmission System , shall be performed only by Customer or by contractors selected by Customer based on Good Utility Practice.

3.8.8 If RGE is required (in order to comply with an order of a governmental or regulatory agency or the NYISO) at any time to invest in any new equipment or facilities, or to modify (including an addition) or replace any part of the RGE Interconnection Facilities, (a "Regulatory Upgrade") in order to provide Interconnection Service, Customer shall reimburse RGE for: (a) all of its Reasonable costs and expenses described and permitted in Sections 5.1 and 5.2 which are incurred by RGE for the design, engineering, procurement, construction, installation, and any start up testing of any Regulatory Upgrade, and (b) any Reasonable costs described and permitted in Sections 5.1 and 5.2 which are incurred by RGE to operate and Maintain such Regulatory Upgrade.

3.8.9 Customer shall compensate RGE, in accordance with Article 5 of this Agreement, for all Reasonable costs and expenses described and permitted in Article 5 which are incurred by RGE in modifying, replacing or adding to the RGE Interconnection Facilities as required by Good Utility Practice (the "GUP Upgrades") to permit RGE to exercise its rights and fulfill its obligations under this Agreement; provided, however that: (a) Customer shall have no obligation to reimburse any costs of any GUP Upgrade made by RGE without it having first provided thirty (30) days written notice of such GUP Upgrade, which notice shall include a brief description of such GUP Upgrade and an estimate of the cost thereof; and (b) RGE shall not seek, or be entitled to reimbursement of any of such costs or expenses to the extent that they are properly included or includable in RGE's capital accounts or rate base for recovery from RGE's ratepayers. Costs associated with Transmission System Improvements, Regulatory Upgrades, and GUP Upgrades shall not be included or includable in RGE's capital accounts or rate base for recovery from ratepayers to the extent that the improvement or upgrade was needed, as demonstrated in a writing provided by RGE to Customer, to interconnect the Plant to the Transmission System and to accept and/or purchase power from Customer in the event Customer and RGE decide to enter into a separate agreement related to such power purchases in order to allow Customer to maintain its PURPA status. The Parties agree that certain upgrade costs may be incurred by RGE with respect to facilities that serve a dual purpose in both permitting Customer to take power from the Transmission System and to transmit power to the Transmission System. With regard to such dual purpose facilities, RGE would not seek to recover from ratepayers, and Customer would be responsible for, that part of the dual purpose upgrade costs that would not have been incurred had RGE not been required to interconnect the Plant to the Transmission System and/or enter into a power purchase agreement for the purpose stated above.

3.8.10 Customer shall modify, at its sole cost and expense, the Customer Interconnection Facilities, as may be Reasonably required to conform to Good Utility Practice. Upon completion of any additions, modification, or replacements to the Customer Interconnection Facilities, that may Reasonably be expected, in Customer's sole judgment to affect the Transmission System, but no later than ninety (90) days thereafter, Customer shall issue one copy of "as built" drawings to RGE. Upon RGE's completion of any Transmission System Improvements, GUP Upgrades, or Regulatory Upgrades as contemplated in Sections 3.8.4, 3.8.9, or 3.8.8, respectively, but no later than ninety (90) days thereafter, RGE shall issue one copy of "as built" drawings to Customer.

3.9 Inspections. Upon 24 hours' notice, and during Customer's normal business hours, Monday through Friday, except for federal holidays, RGE shall, at its own expense, have the right to inspect or observe all maintenance activities, equipment tests, installation work, construction work, and modification work to the generating equipment component of the Plant, the Customer Interconnection Facilities, and/or the Joint Use Facilities owned by Customer. If RGE observes any deficiencies or defects with respect thereto that might Reasonably be expected to adversely affect the Transmission System, including the RGE Interconnection Facilities, RGE shall notify Customer, and Customer shall make such corrections as are necessitate by Good Utility Practice.

3.10 Information Reporting Obligations.

3.10.1 Customer shall promptly provide RGE with all relevant information, documents, or data related to or associated with the generating equipment components of the

Plant, the Customer Interconnection Facilities, and/or the Joint Use Facilities owned by Customer that would be expected to affect the Transmission System, and which is Reasonably requested by NERC, NPCC, NYISO, FERC, NYPSC, or by RGE, which disclosure shall be subject to Reasonable restrictions required by Customer regarding the disclosure of commercially sensitive information or Critical Energy Infrastructure Information (as that term is defined at 18 CFR § 388.113) provided by Customer.

3.10.2 Customer shall supply accurate, complete, and reliable information in response to Reasonable data requests necessary for operations, maintenance, regulatory requirements, and analysis of the Transmission System. Such information may include metered values for MW, MVAR, voltage, current, amperage, automatic voltage regulator status, automatic frequency control, dispatch, frequency, breaker status indication, or any other information related to or associated with the generating equipment components of the Plant, the Customer Interconnection Facilities, and/or the Joint use Facilities owned by Customer and Reasonably required by RGE for reliable operation of the Transmission System pursuant to Good Utility Practice and/or applicable laws, regulations, and governmental orders. As of the Effective Date, such data that Customer needs to provide is set forth in Schedule I of this Agreement, and such data may be revised by mutual agreement.

3.10.3 Information pertaining to energy transfer through the Customer Interconnection Facilities shall be gathered by RGE through its current equipment for electronic transmittal to RGE using one or more of, but not limited to, the following: SCADA equipment, remote terminal unit (“RTU”) equipment, remote access pulse recorders, or analog telemetry. Information pertaining to RGE Interconnection Facility parameters shall be obtained from RGE’s RTUs in accordance with Schedule A to this Agreement.

3.11 Revenue Metering.

3.11.1 RGE shall own and Maintain (at RGE's sole cost and expense), and have the right to change the location of, all Revenue Meters and instrument transformers and appurtenances associated with Revenue Meters, analog equipment (transducers and telemetry), conduct meter accuracy and tolerance tests, and prepare all calibration reports required for equipment that measures energy transfers between and RGE. All meter accuracy and tolerance testing hereunder shall be in accordance with Good Utility Practice. RGE shall notify , as far as practicable but not less than 24 hours in advance of such testing, and, at option, may have a representative present during such testing. A list of the current metering equipment is provided in Schedule G.

3.11.2 If at any time any Revenue Metering and analog equipment is found to be inaccurate by a margin of greater than that allowed under the applicable regulatory criteria, rules, and standards, such Revenue Metering and analog equipment shall be made accurate or replaced at RGE's expense. Meter readings for the period of inaccuracy shall be adjusted insofar as the extent of the inaccuracy can be Reasonably ascertained by using Customer's parallel metering. Each Party shall comply with any Reasonable request of the other concerning the sealing of Revenue Meters, the presence of a representative of the other Party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of energy sold in the NYISO's wholesale markets. If either Party believes that there has been a Revenue meter or analog equipment failure or stoppage, it shall immediately notify the other Party thereof.

3.11.3 If at any time a Generator Meter or other analog equipment is found to be inaccurate by a margin of greater than that allowed under the applicable regulatory criteria, rules, and standards, such Generator Meter or analog equipment shall be made accurate or replaced at Customer's expense. Each Party shall comply with any Reasonable request of the other concerning the sealing of Generator Meters, the presence of a representative of the other Party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of energy sold in the NYISO's wholesale markets. If either Party believes that there has been a Generator Meter or analog equipment failure or stoppage, it shall immediately notify the other Party thereof.

3.11.4 RGE shall own and Maintain, at RGE's expense, all additional or updated metering and associated equipment needed in accordance with Good Utility Practice.

3.11.5 RGE shall own and Maintain, at RGE's expense, equipment for real-time communications, real-time power (real and reactive), hourly kWh information, and such other information as required by RGE related to the operation of the Revenue Meters and Generator Meters. Customer shall maintain operating telephone links to provide information deemed necessary by the NYISO, or as Reasonably deemed necessary by RGE, to integrate operation of the Plant with the Transmission System. This section 3.3.11.5 shall only apply to Customer with respect to communication equipment installed or modified after the Effective Date.

3.12 Remote Terminal Units. RGE shall Maintain, and own its RTUs at the Customer's Interconnection Facilities as specified in Schedule A to this Agreement. (A list of the data currently provided to RGE from the RTUs is listed in Schedule H of this Agreement.) RGE and Customer recognize that the RTU requirements may require revision to the extent Customer elects to participate in the NYISO. RGE shall not be responsible for Maintaining, at its expense, Customer's RTUs at the Customer interconnection Facilities.

3.13 Emergency Procedure.

3.13.1 In accordance with the operating procedures (see Exhibit F), RGE shall provide Customer's electric dispatcher with prompt verbal notification of Emergencies affecting the Transmission System that may Reasonably be expected to affect Customer's operation of the Plant, and Customer shall provide RGE and the NYISO with prompt verbal notification of Emergencies which might Reasonably be expected to affect the Transmission System and/or RGE's operations. Such notification shall describe the Emergency, the extent of the damage or deficiency, the anticipated length of the outage, and the corrective action taken and/or to be taken. RGE shall follow up as soon as practicable with written notification in accordance with Article 19 of this Agreement.

3.13.2 If in the good faith judgment of a Party, an Emergency endangers or might endanger life or property, the Party recognizing the problem shall take such immediate action as is Reasonable and necessary to prevent, avoid, or mitigate injury, danger, and loss; provided that no Party shall be liable to the other Party for any action taken in response to an Emergency so long as such action or response was made in good faith and was consistent with Good Utility Practice and the Services Tariff and OATT.

3.13.3 Either or both Parties and/or the NYISO may, consistent with Good Utility Practice, take whatever actions or inactions it or they deem necessary during an Emergency to: (a) preserve public health and safety; (b) preserve the integrity of the Transmission System, RGE's distribution system, or the Plant, as applicable; (c) limit or prevent damage; and (d) expedite restoration of service. Customer shall have the right at its option to disconnect the Plant from the Transmission System, in accordance with disconnect procedures that reflect Good Utility Practice, until normal operations are restored.

3.14 Interconnection Service Interruptions.

3.14.1 If at any time, in the Reasonable exercise of the RGE's or the NYISO's judgment, exercised in accordance with Good Utility practice or in accordance with the Services Tariff or the OATT, the operation of the Plant would have an adverse impact on the quality of distribution service rendered by RGE, or would interfere with the safe and reliable operation of the Transmission System, RGE or the NYISO, as applicable, may discontinue Interconnection Service and/or curtail, interrupt or reduce energy delivered from the Plant until the conditions has been corrected.

3.14.2 Unless RGE or the NYISO perceives that an Emergency exists, or that the risk of one is imminent, RGE or the NYISO shall give Customer's electric dispatcher Reasonable verbal notice, in accordance with the operating procedures (see Exhibit F), of its intention to discontinue, curtail, interrupt or reduce Customer's Interconnection Service in response to an interfering condition, and, where practical, allow suitable time for Customer to remove the interfering condition before any such discontinuation, curtailment, interruption or reduction of service under this Section 3.14 shall be made pursuant to Good Utility Practice and/or the NYISO's Services Tariff or OATT

3.14.3 Separate from an Emergency or interfering condition, RGE may be required to request Customer to reduce or discontinue its Interconnection Service, if such Interconnection Service could adversely impact RGE's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. Except in cases of Emergency, Customer will reduce or discontinue its Interconnection Service within 30 minutes following a request from RGE that Customer reduce or discontinue its Interconnection Service. RGE shall not be liable to Customer for any damages or losses suffered by Customer as a result of reduction or discontinuance of deliveries of electricity to Customer pursuant to this Section 3.14.3.

3.14.4 In the event of any discontinuation, curtailment, interruption or reduction, and in accordance with the operating procedures (see Exhibit F), RGE shall promptly confer with Customer's electric dispatcher regarding the interfering conditions that gave rise to the discontinuation, curtailment, interruption or reduction, and RGE shall give Customer RGE's recommendation concerning the timely correction thereof. In the event Interconnection Service is discontinued, curtailed, interrupted or reduced under this Section 3.14 due to RGE's failure to Maintain the RGE Interconnection Facilities or Joint Use Facilities owned by RGE, to the extent required by, and in accordance with, Good Utility Practice and the NYISO's Services Tariff and OATT, as applicable, and subject to any power purchase agreement between the Parties, RGE shall compensate Customer for the costs Reasonably incurred by Customer that are attributable to the discontinuation, curtailment, interruption or reduction and restoration of Interconnection Service , but only to the extent RGE's failure stems from RGE's gross negligence or willful misconduct. RGE shall restore full Interconnection Service as soon as practicable consistent with Good Utility Practice and the NYISO's Services Tariff and OATT.

3.15 Scheduled Maintenance Notification and Coordination. RGE shall, as soon as practicable, and in accordance with the operating procedures (see Exhibit F), give written notice to Customer's electric dispatcher regarding the timing of any scheduled maintenance of the Transmission System which might Reasonably be expected to affect the operation of the Plant. RGE shall, to the extent practicable, schedule any testing, shutdown, or withdrawal of those aspects of the Transmission System to coincide with Customer's scheduled outages of the Customer Interconnection Facilities. In the event RGE is unable to schedule the outage of its facilities to coincide with Customer's schedule, RGE shall use all Reasonable efforts to notify Customer in advance of the reasons for the facilities' outage, of the time scheduled for the outage to take place, and of its expected duration. If RGE does schedule the outage of those aspects of the Transmission System to coincide with Customer's schedule, then RGE shall not be obligated to, and shall be free from any liability for failing to, modify its maintenance schedule to accommodate Customer's desire to modify its outage (including the length of such outage) once such outage has commenced. The Parties shall use Reasonable efforts to coordinate the maintenance scheduling for their respective Interconnection Facilities. Customer shall, as soon as practicable and in accordance with the operating procedures (see Exhibit F), give written notice to RGE and the NYISO regarding the timing of any scheduled maintenance of the Customer Interconnection Facilities which might Reasonably be expected to affect the operation of the Transmission System. Customer shall, to the extent practicable, schedule any testing, shutdown, or withdrawal of these facilities to coincide with RGE's scheduled outage of the RGE Interconnection Facilities.

3.16 Safety

3.16.1 General. Subject to Article 9, RGE and Customer agree to be solely responsible for, and assume all liability for, the safety and supervision of their own employees, agents, representatives, and subcontractors.

3.16.2 RGE and Customer agree that all work performed by either Party which might Reasonably be expected to affect the operations of the other Party shall be performed in accordance with all applicable laws, rules, and regulations pertaining to the safety of persons or property, and Good Utility Practice.

3.17 Electric Switching and Tagging Applications and Rules.

3.17.1 RGE shall comply with the Electric Switching and Tagging Applications and Rules, as the same may be amended or superseded, at the Points of Interconnection. RGE will notify Customer of any changes in the Electric Switching and Tagging Applications and Rules.

3.17.2 Customer shall be responsible for all switching, tagging and mark-ups on Customer's side of the Points of Interconnection, as such points are set forth in Schedule D to this Agreement, in accordance with RGE's switching and tagging rules. RGE shall maintain and be responsible for all switching, tagging, and mark-ups at the Points of Interconnection, and on RGE's side of the Points of Interconnection; provided, however, that RGE shall perform switching, tagging and mark-ups with respect to RGE's equipment and facilities, including Joint Use Facilities owned by RGE, located on Customer's side of the Points of Interconnection.

3.17.3 Customer, in accordance with the Good Utility Practice, shall be responsible for training and testing its operators for inclusion on a Joint Tag List.

ARTICLE 4
OPERATIONS

4.1 General.

4.1.1 RGE and Customer agree to operate the Plant (as applicable), any facilities, or equipment that might Reasonably be expected to have an impact on the operations of the other Party in a safe and efficient manner and in accordance with all applicable federal, state, and local laws, the rules, regulations and codes of governmental agencies with jurisdiction over the Parties and/or the facilities or equipment, and Good Utility Practice.

4.1.2 RGE and Customer agree to operate the RGE Interconnection Facilities and Customer Interconnection Facilities, respectively, in accordance with the directives of the NYISO.

4.1.3 At its cost and expense, Customer shall be required to comply with the Reasonable and lawful requests, orders and directives of RGE concerning the operation of the Customer Interconnection Facilities to the extent such requests, orders, or directives of RGE are issued pursuant to Good Utility Practice, and are not discriminatory.

4.1.4 In the event Customer believes that a request, order, or directive of RGE is inconsistent with the provisions of Section 4.1.1, it shall nevertheless comply with the request, order, or directive of RGE pending resolution of the dispute under Article 12 of this Agreement. The Parties agree to cooperate in good faith to expedite the resolution of any disputes arising under this Section 4.1.4.

4.2 Customer's Operating Obligations.

4.2.1 Customer is responsible for the proper synchronization of the Plant to the Transmission System. Customer shall request permission from RGE's dispatch personnel, or the NYISO, prior to opening and/or closing circuit breakers of the RGE Interconnection Facilities in accordance with the Electric Switching and Tagging Applications and Rules.

4.2.2 Customer shall advise RGE, if requested, of the Plant's capabilities, if any, of participation in system restoration and black start procedures.

4.2.3 The electrical supply to the Points of Interconnection shall be in the form of three-phase 60 Hz alternating current at the nominal system voltage at the Points of Interconnection.

4.3 Voltage or Reactive Control Requirements.

4.3.1 Except as provided in applicable tariffs or the Standby Service Agreement between RGE and Customer, dated October 1, 2004, Customer shall operate the Plant to maintain a power factor of 0.85 or higher at the Points of Interconnection. If Customer fails to maintain a power factor of 0.85 or higher at the Points of Interconnection, Customer shall, at Customer's election, either (a) reimburse RGE for all costs and expenses incurred by RGE for installing, repairing, or replacing equipment used to maintain the capability for Customer to operate the Plant at a power factor of 0.85 or higher at the Points of Interconnection, or (b) pay to RGE the higher of (i) $0.60 per reactive kilovolt-ampere, or (ii) the reactive power charge found in any applicable RGE tariff approved by the NYPSC or FERC, as applicable. In an Emergency, and if the capabilities of the Plant permit, the NYISO may request Customer to raise or lower the voltage at the Points of Interconnection which may result in providing reactive power to the Transmission System or absorbing reactive power from the Transmission System.

4.3.2 Customer shall, with respect to operation of the Customer Interconnection Facilities, comply with the NYISO's system restoration procedures, as set forth in the NYISO Emergency Operations Manual and NYISO System Restoration Manual, and any successor manuals, and with RGE's local system restoration plan, which plan shall be provided to Customer by RGE upon Customer's request.

4.3.3 RGE or the NYISO may from time to time Reasonably request, order, or direct Customer to adjust the controls of the Customer Interconnection Facilities, within the capabilities of the Plant and subject to Customer's Host Load obligations, that impact the Transmission System. Customer agrees to comply with such requests, orders, or directions.

4.3.4 If RGE determines that any of the Customer Interconnection Facilities or associated equipment fail to perform as designed, or that Customer has failed to perform proper testing or maintenance of such equipment, RGE will notify Customer to take corrective action, and will specify a Reasonable deadline by which such corrective actions must be completed. On or before such deadline, Customer must demonstrate to RGE's Reasonable satisfaction that Customer has initiated such corrective actions. If Customer fails to demonstrate to RGE's Reasonable satisfaction that it has initiated or completed such corrective actions within the specified deadline, RGE may open the interconnection between RGE and Customer until such corrective action is initiated or completed.

4.4 Auditing of Accounts and Records.

Within two (2) years following a calendar year, Customer and RGE shall have the right, during normal business hours, to audit each other's accounts and records pertaining to transactions under this Agreement for that calendar year at the offices where such accounts and records are maintained; provided, however, that appropriate notice shall have been given prior to any audit, and provided further that the audit shall be limited to those portions of such accounts and records that relate to the transactions at issue. The Party being audited will be entitled to review the audit report and nay supporting materials. To the extent that audited information includes confidential information, the auditing Party shall designate an independent auditor to perform such audit. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

ARTICLE 5
COST RESPONSIBILITIES AND BILLING PROCEDURES

5.1 Cost Responsibilities for Interconnection Service.

5.1.1 Customer will pay RGE the Reasonable costs actually incurred for the design, engineering, procurement, construction, installation and/or start up testing of the Transmission System Improvements (as described in Section 3.8.4), the GUP Upgrades (as described in section 3.8.9) and the Regulatory Upgrades (as described in Section 3.8.8) (together, the "RGE Projects"). Such reimbursable costs under this Section 5.1 shall include, without limitation: (i) RGE's labor costs; (ii) costs of materials and equipment; (iii) contractor costs; (iv) any taxes or governmental fees incurred a direct result of the RGE Projects; (v) administrative and general expenses incurred as a direct result of the RGE Projects; (vi) permitting and licensing costs and expenses; and (vii) other related costs incurred as a direct result of the RGE Projects; but shall not include any of such costs or expenses to the extent that they are properly includable in RGE's capital accounts or rate base for recovery from RGE's ratepayers.

5.1.2 Customer will pay RGE an amount equal to the estimated cost of any RGE Projects which may be undertaken in accordance with this Agreement, which estimated costs shall be subject to adjustment in accordance with Section 5.1.4 below. Customer will reimburse RGE (on an after-tax basis) for any taxes that are actually incurred by RGE as a result of a determination by the Internal Revenue Service pursuant to Section 118(b) of the Code of 1986, as amended, that the facilities or equipment installed by RGE or a portion thereof was a "Contribution-In-Aid-Of-Construction." RGE acknowledges Customer's right to participate in any negotiations or litigation with the Internal Revenue Service on this matter.

Customer will be liable to RGE for payment immediately upon notice from RGE to Customer that the Internal Revenue Service has made a final determination.

5.1.3 If a portion of the costs paid by Customer to RGE pursuant to Section 5.1.2 is included in RGE's revenue requirement and recovered from RGE ratepayers, RGE will refund to Customer that portion of the costs paid by Customer that are so included in the applicable revenue requirement.

5.1.4 All payments required under this Section 5.1 will be determined initially by RGE on an estimated basis, and then adjusted for actual costs incurred. When the actual costs resulting from this Section 5.1 are known, RGE will issue a Final Report to Customer showing such actual costs in Reasonable detail. RGE will determine the difference between the estimated costs already paid by Customer and the actual costs of the RGE Projects which are reimbursable as described in this Section 5.1. To the extent that the actual costs incurred by RGE exceed the estimated costs paid by Customer, Customer will pay RGE an amount equal to the difference between the amount paid by Customer and the actual costs. To the extent the estimated costs paid by Customer exceed the actual costs incurred by RGE, RGE will refund the difference between the actual costs and the amount paid by Customer, Payments pursuant to this Section 5.1 will be made within forty-five (45) days of the date RGE delivers its Final Report to Customer for the actual costs incurred.

5.1.5 Customer will pay to RGE any amounts due under this Section 5.1 in accordance with a payment schedule to be determined by mutual agreement of the Parties.

5.1.6 If Customer for whatever reason goes out of business or otherwise abandons the Plant and any RGE Projects have already been partially or completely constructed, Customer will be responsible for reimbursing RGE for all of the unrecovered costs payable under this Section 5.1 that would not have been incurred by RGE but for this Agreement.

5.1.7 Except as otherwise provided in this Section 5.1.7, Customer will be responsible for all costs relative to Customer's allocated share of the RGE Interconnection Facilities described in Schedule A to this Agreement. Customer's monthly costs and expenses associated with the operation and maintenance of the RGE Interconnection Facilities will be as set forth in Schedule C attached hereto. Customer shall not be responsible for the costs of operation, maintenance, repairs or any other expenses of RGE associated with the RGE Interconnection Facilities or the Transmission System or Joint use Facilities owned by RGE which are in place as of March 16, 2006, but instead this Section 5.1.7 shall apply only with respect to operation, maintenance, repair and similar costs associated with additions, modifications or replacements of the RGE Interconnection Facilities or the Transmission System in connection with the RGE Projects undertaken by RGE in accordance with Article 3 hereof subsequent to March 16, 2006. RGE shall update Schedule C periodically, and after consultation with Customer, to the extent required to reflect the costs and expenses associated with additions, modifications, or replacements of the RGE Interconnection Facilities or the Transmission System required in accordance with Article 3 hereof.

5.2 Cost Responsibilities for Services. For services which have identified price/rate schedules set forth herein, payment shall be in accordance with said schedules as in effect from time to time. For services which require reimbursement but do not have identified price/rate schedules, the Parties shall, to the extent practicable, agree upon the price/rate prior to the performance or provision of said services.

5.3 Billing Procedures.

5.3.1 Within ten (10) days after the first day of each month, each Party shall prepare an invoice for those reimbursable services provided to the other Party under this Agreement during the preceding month.

5.3.2 Each invoice shall delineate the month in which the services were provided, shall fully describe the services rendered, and shall be itemized to reflect the services performed or provided.

5.3.3 The invoice shall be paid within forty-five (45) days of issuance. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party.

5.4 Interest on Unpaid Balances.

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology set forth in FERC'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 the other Party.

5.5 Billing Disputes: Acceptance of Partial Payments. In the event of a billing dispute between RGE and Customer, each Party shall continue to provide services as long as both Parties (a) continue to make all payments not in dispute, and (b) when the disputed amount exceeds $50,000, the Parties agree to place the disputed amount into an interest-bearing escrow account pending resolution of such dispute, in accordance with an escrow agreement to be negotiated between the Parties under which the Party owed the disputed amount shall select an independent escrow agent. Acceptance by either Party of partial payment of an amount invoiced or otherwise due from the other Party shall not constitute waiver by the accepting Party of any claim for the unpaid amount. As part of the resolution of the disputed amount, the Parties shall determine the disposition of any interest accrued on the funds placed in the escrow account. Any directives to the escrow agent to release funds from the escrow account shall be on at least one (1) business day's notice to the other Party.

ARTICLE 6
DOCUMENTATION

6.1 Drawings. Each Party shall be responsible for drawing updates and corrections to its respective drawings of the RGE Interconnection Facilities or the Customer Interconnection Facilities, respectively, and shall provide copies thereof to the other Party, at the expense of the other Party, as soon as practicable after the updates or corrections are made. The Parties shall develop mutually agreeable procedures for updating drawings.

ARTICLE 7
CONFIDENTIALITY

7.1 Confidentiality of RGE. RGE shall hold in confidence, unless required to be disclosed by judicial or administrative process or other provisions of law, all documents and information furnished by Customer in connection with this Agreement which is conspicuously marked "Confidential"; except to the extent that such information or documents are (a) generally available to the public other than as a result of a disclosure by RGE, (b) available to RGE on a non-confidential basis prior to disclosure to RGE by Customer, or (c) available to RGE on a non-confidential basis from a source other than Customer, provided that such source is not known, and by Reasonable effort could not be known, by RGE to be bound by a confidentiality agreement with Customer, or otherwise prohibited from transmitting the information to RGE by a contractual, legal or fiduciary obligation. RGE shall not release or disclose such information to any other person, except to its employees on a need-to-know basis who have been advised of the confidentiality provisions of this Section 7.1 and have agreed in writing to comply with such provisions. RGE shall promptly (and in any case prior to sharing any confidential information of Customer) notify Customer if it receives notice or otherwise concludes that the production of any information subject to this Section 7.1 is being sought under any provision of law so that Customer may oppose such request. RGE may utilize information subject to this Section 7.1 in any proceeding under Article 12 of this Agreement, subject to a confidentiality agreement with the participants of the dispute resolution process.

7.2 Confidentiality of Customer. Customer shall hold in confidence, unless required to be disclosed by judicial or administrative process or other provisions of law, all documents and information furnished by RGE in connection with this Agreement which is conspicuously marked “Confidential”, except to the extent that such information or documents are (a) generally available to the public other than as a result of a disclosure by Customer, (b) available to Customer on a non-confidential basis prior to disclosure to Customer by RGE, or (c) available to Customer on a non-confidential basis from a source other than RGE, provided that such source is not known, and by Reasonable effort could not be known, by Customer to be bound by a confidentiality agreement with RGE or otherwise prohibited from transmitting the information to Customer by a contractual, legal or fiduciary obligation. Customer shall not release or disclose such information to any other person, except its employees on a need-to-know basis who have first been advised of the confidentiality provisions of this Section 7.2 and have agreed to comply in writing with such provisions. Customer shall promptly (and in any case prior to sharing any confidential information of RGE) notify RGE if it receives notice or otherwise concludes that the production of any information subject to this Section 7.2 is being south under any provision of law so that RGE may oppose such request. Customer may utilize information subject to this Section 7.2 in any proceeding under Article 12 of this Agreement, subject to a confidentiality agreement with the participants to the dispute resolution process.

7.3 Confidentiality of Audits. The independent auditor performing any audit, as referred to in Section 4.3 of this Agreement, shall be subject to a confidentiality agreement between the auditor and the Party being audited. The report of such auditor, and any other information produced by the auditor in connection with such audit, shall be treated as confidential information of the Party being audited for purposes of Sections 7.1 or 7.2 above, as the case may be, for all purposes under this Agreement and without the necessity of such report being conspicuously marked “Confidential”.

7.4 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party’s breach of its obligations under this Article 7. Each Party accordingly agrees, subject to Article 18 of this Agreement, that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party breaches or threatens to breach its obligations under this Article, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law.

7.5 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article 7 to the contrary, and pursuant to 18 CFR § 1b.20, if the FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement or the OATT, the Party shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Party must, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. Each Party is prohibited from notifying the other Party to this Agreement prior to the release of the confidential information to the FERC or its staff. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request to release confidential information has been received by FERC, at which time the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations. A Party shall not be liable for any losses, consequential or otherwise, resulting from that Party divulging confidential information pursuant to a FERC or state regulatory body request under this paragraph.

ARTICLE 8
EVENTS OF DEFAULT

8.1. Events of Default. Any of the following shall constitute an event of default under this Agreement:

(a) The failure to pay any amount when due and the non-paying Party does not cure such failure within thirty (30) calendar days after notice of such non-payment from the other Party;

(b) A breach of any other term or condition of this Agreement, including, but not limited to, the breach of a representation, warranty or covenant made in this Agreement, if such breach is not cured within thirty (30) days after notice to the breaching

Party, provided that if such breach cannot Reasonably be cured within such thirty (30) day period, then the breaching Party shall have such additional time as is Reasonable to effect such cure without being in default under this Agreement, provided however that such Party shall commence the cure of such breach within such thirty (30) day period and shall proceed to complete such cure with Reasonable diligence;

(c) The appointment of a receiver or liquidator or trustee for either Party or of any property of a Party, and such receiver, liquidator or trustee is not discharged within sixty (60) days;

(d) The entry of a decree adjudicating a Party or any substantial part of the property of a Party bankrupt or insolvent, and such decree is continued undischarged and unstayed for a period of sixty (60) days; or

(e) The filing of a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law by a Party.

(f) For the avoidance of doubt, no breach shall exist where a Party's failure to discharge an obligation (other than the payment of money) under this Agreement is the result of a force majeure as defined in Article 11 or the result of an act or omission of the Party.

8.2 Notice, Cure, and Remedies.

(a) Upon the occurrence of an event of default, the Party not in default may give written notice of the default to the defaulting Party. Such notice shall set forth, in Reasonable detail, the nature of the default and, where known and applicable, the steps necessary to cure such default.

(b) If the defaulting Party fails to cure such default or take such steps as provided under subparagraph (a) above, this Agreement may be terminated by written notice to the Party in default hereof. This Agreement shall thereupon terminate and the non-defaulting Party may exercise all such rights and remedies as may be available to it to recover damages, subject to Article 18 of this Agreement, caused by such default.

(c) Notwithstanding the foregoing, upon the occurrence of any such event of default, the non-defaulting Party shall be entitled (i) to commence an action to require the defaulting Party to remedy such default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (ii) to exercise such other rights and remedies as it may have at equity or at law.

8.3 Right to Take Immediate Action. Notwithstanding anything in this Agreement to the contrary, Customer's failure to comply with the provisions of Sections 4.1 or 4.2 of this Agreement shall constitute an event of default, and if such event of default is Reasonably likely to have an immediate and material adverse effect on the Transmission System, RGE shall have the right to take immediately all Reasonable steps and/or to exercise immediately all remedies available under this Agreement, or at law or in equity, including the right to temporarily disconnect the Customer Interconnection Facilities from the RGE Interconnection Facilities and the Transmission System, in order to prevent or mitigate an adverse effect on the Transmission System.

ARTICLE 9
INDEMNIFICATION

9.1 Customer's Indemnification. Customer shall indemnify, hold harmless, and defend RGE, its parent, Affiliates, and successors, and their respective officers, directors, employees, agents, subcontractors, and successors from and against any and all claims, demands, liabilities, costs, losses, judgments, damages, and expenses (including, without limitation, Reasonable attorney and expert fees and disbursements incurred by RGE in any action or proceeding between RGE and a third party or Customer) for damage to property, injury to or death of any person, including RGE's employees, Customer's employees and their Affiliates' employees, or any third parties, to the extent caused wholly or in party by any negligent or intentional act or omission by Customer and/or its officers, directors, employees, agents, contractors, and subcontractors arising out of or connected with this Agreement.

9.2 RGE's Indemnification. RGE shall indemnify, hold harmless, and defend Customer, its parent, Affiliates, and successors, and their respective officers, directors, employees, agents, subcontractors, and successors from the against any and all claims, demands, liabilities, costs, damages, and expenses (including, without limitation, Reasonable attorney and expert feels and disbursements incurred by Customer in any action or proceeding between Customer and a third party or RGE) for damage to property, injury to or death of any person, including RGE's employees, Customer's employees and their Affiliates' employees, or any third parties, to the extent caused wholly or in part by any negligent or intentional act or omission by RGE and/or its officers, directors, employees, agents, contractors, and subcontractors arising out of or connected with this Agreement.

9.3 Indemnification Procedures. If either Party intends to seek indemnification under this Article 9 from the other Party, the Party seeking indemnification shall give the other Party notice of such claim within one hundred and twenty (120) days of the commencement of, or the Party's actual knowledge of, such claim or action. Such notice shall describe the claim in Reasonable detail, and shall indicate the amount (estimated, if necessary) of the claim, if possible, that has been, or may be sustained by, said Party. To the extent that the other Party will have been actually and materially prejudiced as a result of the failure to provide such notice, such notice will be a condition precedent to any liability of the other Party under the provisions for indemnification contained in this Agreement. Neither Party may settle or compromise any claim that affects or that may affect the other Party's indemnification obligations under this Agreement without the prior consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed.

9.4 Survival. The indemnification obligations of each Party under this Article 9 shall continue in full force and effect regardless of whether this Agreement expires, terminates or is canceled. Such obligations shall not be limited in any way by any limitation on insurance, by the amount or types of damages, or by any compensation or benefits payable by the Parties under Workers' Compensation Acts, disability benefit acts or other employee acts, or otherwise.

ARTICLE 10
INSURANCE

10.1. Maintenance of Insurance Coverages. Customer and RGE each agree to maintain for the term of this Agreement, as set forth in Article 2, each at its own cost and expense, general liability, excess (umbrella) liability, auto liability, and workers' compensation insurance relating to its property and facilities in the manner and amounts, and for the durations set forth in Schedule B to this Agreement.

10.2. Certificates of Insurance. Each Party agrees to furnish the other Party with certificates of insurance, which certificates shall be furnished concurrently with the execution and delivery of this Agreement and fifteen (15) days after the expiration date of each such policy and/or certificate evidencing the insurance coverage set forth in Schedule B to this Agreement.

10.3. Notice Requirements. Every contract of insurance providing the coverages required in Schedule B to this Agreement shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until ninety (90) days from the date written notice thereof is actually received by said Party." Upon receipt of any notice of reduction, cancellation or expiration, the Party responsible to maintain such insurance shall immediately notify the other Party in accordance with Article 19 of this Agreement.

10.4. Additional Insureds. Unless the other Party is self-insured pursuant to section 10.8, each Party shall be named as additional insureds, as their interests may appear on the general liability, excess (umbrella) liability, and auto liability insurance policies set forth in Schedule B maintained by the other Party as regards liability under this Agreement, and such insurance shall be considered as primary insurance carried by such additional insured Party as respects the liability of the insured Party hereunder.

10.5. Contents of Certificates of Insurance. The certificates of insurance to be provided by the Parties as required in Section 10.2 above shall provide the following information:

(i) Name of insurance company, policy number, effective date, and expiration date;

(ii) The coverage required and the limits on each;

(iii) A statement indicating that the insureds shall receive at least ninety (90) days prior written notice of cancellation or reduction of liability limits with respect to said insurance policies; and

(iv) To the extent applicable, a statement indicating that the appropriate parties have been named as an additional insureds as their interests may appear.

10.6 Insurer Requirements. All primary insurance policies required herein shall be issued by insurers licensed to transact the business of insurance in the State of New York and have an A.M. Best rating of A or better.

10.7 Endorsements. All insurance policies required herein shall contain, or be endorsed with, a cross liability clause, or a severability of interest clause, specifying that, except for the limits of insurance provided by the policy, each policy will respond on behalf of each insured as if separate policies had been issued to each insured.

10.8 Self-Insurance. To the extent followed in its usual business practice, and for which it has regulatory approval, if required, each party shall be allowed to self-insure all or part of its general liability, excess (umbrella) liability, auto liability, or workers' compensation exposures, provided written confirmation of such self-insurance in the amounts set forth in Schedule B is provided by the self-insured Party to the other Party.

10.9 Subcontractor Insurance Requirements. To the extent applicable, subcontractors of each party must maintain the same insurance requirements stated under this Articles 10 and comply with the Additional Insured requirements herein. In addition, their policies must state that they are primary and non-contributory and contain a waiver of subrogation.

ARTICLE 11
FORCE MAJEURE

11.1. Definition. The term "Force Majeure" as used herein means those causes beyond the Reasonable control of the Party affected, which by the exercise of Reasonable diligence, including Good Utility Practice, that Party is unable to prevent, avoid mitigate, or overcome, including the following: any act of God, labor disturbance (including a strike, or other labor dispute), act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, solar magnetic or other electric system disturbance, breakage or accident to machinery or equipment, order, regulation or restriction imposed by governmental, military or lawfully-established civilian authorities, or any other cause of a similar nature beyond a Party's Reasonable control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming force majeure.

11.2. Economic Hardship. Economic hardship is not considered a Force Majeure event.

11.3. Requirements. If a Party shall rely on the occurrence of a Force Majeure event as a basis for being excused from performance of its obligations under this Agreement, then the Party relying on the event or condition shall: (a) provide prompt notice of such Force Majeure event to the other Party, giving a detailed explanation of the Force Majeure event, including an estimation of tis expected duration and the probable impact on the performance of its obligations hereunder; (b) exercise all Reasonable efforts in accordance with Good Utility Practice to continue to perform its obligations under this Agreement; (c) expeditiously take action to correct or cure the Force Majeure event excusing performance; provided, however, that settlement of labor disputes will be completely within the sole discretion of the Party affected by such labor dispute; (d) exercise all Reasonable efforts to mitigate or limit damages to the other Party; and (e) provide prompt notice to the other party of the cessation of the Force Majeure event giving rise to its excusal from performance.

11.4. Continuing Obligations. A Party shall not be responsible or liable, or deemed, in default with respect to any obligation under this Agreement, other than the obligation to pay money when due, to the extent the Party is prevented from fulfilling such obligation by the occurrence of a Force Majeure event.

11.5. Written Notice. In the event initial notice regarding the occurrence of a Force Majeure event is provided verbally, such notice shall be confirmed in writing as soon as Reasonably possible.

ARTICLE 12
DISPUTES

12.1. Initial Procedures.

12.1.1 Except as provided in Article 5 with respect to billing disputes, any disagreement between RGE and Customer as to their rights and obligations under this Agreement shall first be addressed by the Parties in accordance with this Section 12.1.

12.1.2 Any party seeking the resolution of any disagreement arising out of or relating to or in connection with this Agreement (each a "Dispute") shall provide written notice of such Dispute to the other Party, which notice shall describe the nature of such Dispute. Each such Dispute shall be referred initially for resolution by the respective mid-level management representatives of the Parties listed below (or as may be designated from time to time by each Party by notice to the other), who shall meet at least twice (unless the Dispute is resolved at the first meeting), within thirty (30) days of the receipt by mid-level management of such notice of Dispute, to attempt to resolve such Dispute.

12.1.3 If no resolution is reached by such mid-level management representatives within thirty (30) days of the receipt by mid-level management representatives of such notice of Dispute, then either Party, by notice to the other Party, may refer such Dispute to the respective senior management representatives listed below (or as may be designated)from time to time by each Party by notice to the other) of the Parties

12.1.4 Decisions by mid-level management representatives or senior management representative of the Parties pursuant to this Section 12.1 shall be made by mutual agreement and shall be binding on both Parties. If a Dispute is resolved by mid-level or senior management representatives, then upon the request of either Party, the terms of the resolution and settlement of such Dispute shall be set forth in writing and signed by each party.

12.1.5 In the event that the senior management representatives cannot resolve a Dispute within thirty (30) days of receipt of Notice of the referral of such Dispute to senior management, then such Dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such Dispute to arbitration, each Party may exercise any right or remedy available under this Agreement, at law or in equity.

12.1.6 The representatives of the Parties to whom Disputes will be referred are as follows. Either Party may modify the title and/or add the name a specific individual by providing written notice of the change to the other Party.

Mid-Level Management Representatives:

RGE: Director – Energy Services or its equivalent

Customer: Chief Technical Officer or its equivalent

Senior Management Representatives:

RGE: Vice President – Energy Services

Customer: President

12.2. External Arbitration Procedures.

12.2.1 Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) calendar days of the submission of the Dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel.

12.2.2 In each case, the arbitrator(s) shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration).

12.2.3 The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or NYISO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 12, the terms of this Article 12 shall prevail.

12.3. Arbitration Decisions.

12.3.1 Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) calendar days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner.

12.3.2 The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction.

12.3.3 The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act.

12.3.4 The final decision of the arbitrator must also be filed with the FERC if it affects jurisdictional rates, terms and conditions of service, the Transmission System, either Party's Interconnection Facilities, or the Joint Use Facilities.

12.4. Costs. Each Party shall be responsible for its own costs incurred during the resolution of any Dispute, including any costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) one-half the cost of the single arbitrator jointly chosen by the Parties.

ARTICLE 13

REPRESENTATION

13.1 Representation of RGE. RGE represents and warrants to Customer as follows:

13.1.1 Organization. RGE is a corporation duly organized, validly existing, and in good standing under the laws of the State of New York, and RGE has the requisite corporate power and authority to carry on its business as now being conducted.

13.1.2 Authority Relative to this Agreement. RGE has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly and validly authorized by all required corporate action. This Agreement has been duly and validly executed and delivered by RGE, and assuming that it is duly and validly executed and delivered by Customer constitutes a legal, valid and binding agreement of RGE.

13.1.3 Regulatory Approval. RGE's obligations under this Agreement shall be subject to its receipt of any required approval or certificate from the FERC and other governmental authorities, as appropriate, in form and substance satisfactory to RGE, and the expiration of any time period associated therewith. RGE shall in good faith seek and use Reasonable efforts to obtain such approvals.

13.1.4 Compliance With Law. RGE represents and warrants that it is not in violation of any applicable law, statute, order, rule, regulation promulgated or judgment entered by any federal, state, or local governmental authority, which violation would affect RGE's performance of its obligations under this Agreement. RGE represents and warrants that it will comply with all applicable laws, rules, regulations, codes, and standards applicable to

RGE's performance of this Agreement imposed by any federal, state, and local governmental agencies having jurisdiction over RGE.

13.2 Representations of Customer. Customer represents and warrants to RGE as follows:

13.2.1 Organization. Customer is a limited liability company organized, validly existing, and in good standing under the laws of the State of New York, and Customer has the requisite power and authority to carry on its business as now being conducted.

13.2.2 Authority Relative to this Agreement. Customer has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly and validly authorized by all required action. This Agreement has been duly and validly executed and delivered by Customer and, assuming that it is duly and validly executed and delivered by RGE, constitutes a legal, valid and binding agreement of Customer.

13.2.3 Regulatory Approval. Customer's obligations under this Agreement shall be subject to its receipt of any required approval or certificate from the FERC and other governmental authorities, as appropriate, in form and substance satisfactory to Customer, and the expiration of any time period associated therewith. Customer shall in good faith seek and use Reasonable efforts to obtain such approvals. Nothing in this Agreement shall require Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 2005 or PURPA, as amended.

13.2.4 Compliance with Law. Customer represents and warrants that it is not in violation of any applicable law, statute, order, rule, or regulation, or judgment promulgated or entered, by any federal, state, or local governmental authority, which violation would affect Customer's 's performance of its obligations under this Agreement. Customer represents and warrants that it will comply with all laws, rules, regulations, codes, and standards applicable to Customer's 's performance of this Agreement imposed by any federal, state, and local governmental agencies having jurisdiction over Customer.

13.3 Representation of Both Parties. The representation and warranties in Sections 13.1.4 and 13.2.4 shall continue in full force and effect for the term of this Agreement.

ARTICLE 14

ASSIGNMENT/CHANGE IN CORPORATE IDENTITY

14.1. Successors and Assigns. This Agreement and all of the provisions hereof shall be binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns, but neither this Agreement nor any of the rights, interests, or obligations hereunder shall be assigned by either Party hereto, whether by operation of law or otherwise, without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed, except to an Affiliate of RGE that owns the Transmission System, or to an Affiliate of Customer that owns the Plant and provided that such Affiliate has an equal or greater credit rating and the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement. Any assignment of this Agreement in violation of the foregoing shall be, at the option of the non-assigning Party, void. Notwithstanding the foregoing, (i) either Party may assign this Agreement without the consent of the other Party in connection with the sale, merger, restructuring, or transfer of a substantial portion or all of its assets, so long as the transferee or assignee in such a transaction directly assumes in writing all rights, duties and obligations arising under this Agreement; and (ii) Customer may assign, transfer, pledge or otherwise dispose of its rights and interests hereunder to a trustee or lending institution(s) for the purposes of financing or refinancing the acquisition of the Plant, including upon or pursuant to the exercise of remedies under such financing or refinancing, except that any assignment, transfer, pledge, conveyance, or disposition for purposes of financing or refinancing shall not relieve, or in any way discharge, Customer from the performance of its duties and obligations under this Agreement. RGE agrees to execute and deliver, at Customer's expense, such documents as may be Reasonably necessary to accomplish any such assignment, transfer, pledge, conveyance, or disposition of rights hereunder for purposes of the financing or refinancing of the acquisition of the Plant, so long as RGE's rights under this Agreement are not thereby altered, amended, diminished or otherwise impaired.

14.2. Continuation of Liability and Responsibility. No assignment, transfer, pledge, conveyance, or disposition of rights or obligations under this Agreement by a Party shall relieve that Party from liability and financial responsibility for the performance thereof after any such assignment, transfer, conveyance, pledge, or disposition unless and until the transferee or assignee shall agree in writing to assume the obligations and duties of that Party under this Agreement, and the non-assigning Party has consented in writing to such assumption and to a release of the assigning Party from such liability, which consent shall not be unreasonably withheld, conditioned, or delayed.

14.3. Protection of Rights. If either Party terminates its existence as a corporate entity by merger, acquisition, sale, consolidation, or otherwise, or if all, or substantially all, of such Party's assets are transferred to another person or business entity without complying with this Article 14, the other Party shall have the right, enforceable in a court of competent jurisdiction, to enjoin the first party's successor from using the property in any manner that interferes with, impedes, or restricts such other Party's ability to carry out its ongoing business operations, rights, and obligations.

ARTICLE 15
SUBCONTRACTORS

15.1. Use of Subcontractors Permitted. Nothing in this Agreement shall prevent a Party from utilizing the services of such subcontractors as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services.

15.2. Continuing Obligations. The creation of any subcontractor relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Subject to Article 18 of this Agreement, each Party shall be fully responsible to the other Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

ARTICLE 16
LABOR RELATIONS

16.1 RGE and Customer agree to notify immediately the other Party verbally, to be followed by a written confirmation that shall be mailed via first-class mail no later than seven (7) calendar days after such verbal notice, of any labor dispute (including a strike) or anticipated labor dispute of which its management has actual knowledge that may Reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 17

INDEPENDENT CONTRACTOR STATUS

17.1 Nothing in this Agreement shall be construed as creating any relationship between RGE and Customer other than that of independent contractors.

ARTICLE 18

LIMITATION OF LIABILITY

18.1 Except for indemnity obligations set forth in Article 9 of this Agreement, neither RGE nor Customer, nor their respective officers, directors, agents, employees, parents, Affiliates, successors or assigns, shall be liable to the other Party or its parent, subsidiaries, Affiliates, officers, directors, agents, employees, successors or assigns for claims, suits, actions or causes of action or otherwise for incidental, punitive, special, indirect, multiple or consequential damages (including, without limitation, attorneys' fees or litigation costs) connected with, or resulting from, performance or non-performance of this Agreement, or any actions undertaken in connection with or related to this Agreement, including, without limitation, any such damages which are based upon causes of action for breach of contract, tort (including negligence and misrepresentation), breach of warranty or strict liability. The provisions of this Article 18 shall apply regardless of fault and shall survive termination, cancellation, suspension, completion, or expiration of this Agreement.

ARTICLE 19

NOTICES

19.1. Contact Person. On or prior to the Effective Date, each Party shall indicate to the other Party, by written notice, the appropriate person and their contact information during each eight-hour work shift to contact in the event of an Emergency, a scheduled or forced interruption, or reduction in services. The notice last received by a Party shall be effective until modified in writing by the other Party.

19.2. Written Notice. Except as otherwise provided herein, all notices, requests, claims, demands, invoices, and other communications hereunder shall be in writing and shall be given (and except as otherwise expressly provided herein, will be deemed to have been duly given if so given) by hand delivery, electronic mail, facsimile (confirmed in writing), recognized overnight delivery service or by mail (registered or certified, postage prepaid) to the respective Parties as follows:

To RGE:

New York State Electric & Gas Corporation
James A. Carrigg Center
Corporate Drive, Kirkwood Industrial Park
P.O. Box 5224
Binghamton, New York 13902-5224
Attn: Director, Energy Services
Phone:
Fax:
Email:

To Customer:

RED-Rochester, LLC
1200 Ridgeway Avenue
Suite 2121
Rochester, New York 14615
Attn: Bernard M. Nee
Phone: 585-327-2059
Fax: 585-327-2051
Email: bnee@recycled-energy.com

with copies to:

Ironclad Energy Partners, LLC
500 Waters Edge
Lombard, IL 60148
Attn: Contract Administration
Phone: 630-590-6044

Email: Contracts@ironclad-energy.com

Or such other address as is furnished in writing by such Party; and any such notice or communication shall be deemed to have been given as of the date sent.

19.3. Notice to NYISO. In addition to notifying the other Party, each Party shall provide notice to the NYISO in the event of an Emergency, a scheduled or forced interruption, or reduction in services.

19.4. Emergencies. For all notices related to an Emergency, and to the extent information is known, the notice shall describe the Emergency State, the extent of the damage or deficiency, the expected effect on the operation of RGE's or Customer's facilities and operations, the anticipated duration of the Emergency, and the corrective action taken and/or to be taken. In the event an initial notice is provided verbally, it shall be followed as soon as practicable with written notice.

ARTICLE 20
HEADINGS AND RULES OF INTERPRETATION

20.1 Headings. The descriptive headings of the Articles and Sections of this Agreement are inserted for convenience only and shall not affect the meaning or interpretation of this Agreement.

20.2 Construction. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this Agreement or such Appendix to this Agreement; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

ARTICLE 21
WAIVER

21.1 General. Except as otherwise provided in this Agreement, any failure of a Party to comply with any obligation, covenant, agreement, or condition herein may be waived by the Party entitled to the benefit thereof only by a written instrument signed by such Party granting such waiver, but such waiver shall not operate as a waiver of, or estoppel with respect to, any subsequent failure of the first Party to comply with such obligation, covenant, agreement, or condition.

21.2 No Waiver of Capacity and Energy Service Rights. Termination or Default of this Agreement for any reason by the Customer shall not constitute a waiver of the Customer's legal rights to obtain Capacity Resource Interconnection Service and Energy Resource

Interconnection Service from the NYISO and RGE in accordance with the provisions of the NYISO OATT.

21.3 Writing. Any waiver of this Agreement shall, if requested, be provided in writing.

ARTICLE 22
COUNTERPARTS

22.1 This Agreement may be executed in two or more counterparts, all of which will be considered one and the same Agreement, and each of which shall be deemed an original.

ARTICLE 23
GOVERNING LAW

23.1 General. This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to all applicable federal and state laws, and to all duly promulgated orders and other duly authorized action of governmental authorities having jurisdiction over this Agreement.

23.2 New York Law. This Agreement will be governed by and construed in accordance with the law of the State of New York, without giving effect to any conflict of law principles thereof. Except for those matters covered in this Agreement that are jurisdictional to the FERC, any action arising out of or concerning this Agreement must be brought in the federal or state courts of and for the State of New York. Both Parties hereby consent to the exclusive jurisdiction of the State of New York for the purpose of hearing and determining any action arising out of or concerning this Agreement.

23.3 PURPA Status. Should the Plant lose its status as a qualifying facility under PURPA, RGE and Customer shall take all Reasonable steps necessary to comply with applicable statutes and regulations, RGE and Customer shall use Reasonable efforts to cooperate with each other in fulfilling their obligations under this Section 23.3. Any steps taken by RGE pursuant to this Section shall be at Customer's sole cost.

23.4 Filing of Agreement. The Parties agree that this Agreement will be filed with the FERC under section 205 of the Federal Power Act.

23.5 Reservation of Rights. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of any governmental authorities having jurisdiction over this Agreement. Nothing in this Agreement shall limit the rights of the Parties or of the FERC under sections 205 or 206 of the Federal Power Act and the FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

ARTICLE 24
SEVERABILITY

24.1 In the event that any of the provisions of this Agreement are held to be unenforceable or invalid by any court or regulatory authority of competent jurisdiction, the Parties shall, to the extent possible, negotiate an equitable adjustment to the provisions of this Agreement with a view toward effecting the purpose of this Agreement, and the validity and enforceability of the remaining provisions hereof shall not be affected by such holding.

ARTICLE 25
AMENDMENT

25.1 This Agreement may be amended, modified, or supplemented only be written agreement duly executed by both RGE and Customer.

ARTICLE 26
ENTIRE AGREEMENT

26.1 Entire Understanding. This Agreement constitutes the entire understanding between the Parties, and supersedes any and all previous understandings, oral or written, which pertain to the subject matter contained herein.

26.2 Conflicts. If there is a discrepancy or conflict between or among the terms and conditions of this Agreement and the Appendices hereto, the terms and conditions of this Agreement shall be given precedence over the Appendices, except as otherwise expressly agreed to in writing by the Parties.

26.3 Joint and Several Obligations. Except as otherwise stated herein, the obligations of RGE and Customer are several, and are neither joint nor joint and several.

ARTICLE 27
NO THIRD PARTY BENEFICIARIES

27.1 Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties, any rights, remedies, or benefits under or by reason of this Agreement.

ARTICLE 28
FURTHER ASSURANCES

28.1 The Parties hereto agree to execute and deliver promptly, at the expense of the Party requesting such action, any and all other and further information, instruments and documents that may be Reasonably requested in order to effectuate the transactions contemplated hereby, including but not limited to, such instruments or documents to establish, if necessary, an alternative arrangement, for access to services under this Agreement.

Service Agreement No. ______

IN WITNESS WHEREOF, the Parties have caused their authorized representatives to execute this Agreement as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION

Name: Carl A. Taylor
Title: President and CEO

Name: Joseph J. Syta
Title: VP, Controller & Treasurer

RED-ROCHESTER, LLC

____
Craig Bennett
President

Service Agreement No. _____

IN WITNESS WHEREOF, the Parties have caused their authorized representatives to execute this Agreement as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION	RED-ROCHESTER, LLC
______________________________	______________________________
Name: Title:	Craig Bennett President
______________________________	
Name: Title:	

Schedule A

RGE and Customer Interconnection Facilities and Associated Equipment

1. Customer

RED-Rochester (RED) is a full service Utilities provider to multiple companies at the Eastman Business Park (EBP). Utility services provided include steam at multiple pressures, electricity, chilled water, compressed air, nitrogen, treated process water from Lake Ontario and an industrial wastewater treatment with a plant locate on the Genesee River. A steam-electric cogeneration facility is the key process that makes possible RED's capability to provide reliable utilities service throughout the EBP.

The steam-electric cogeneration facility consists of multiple natural gas fired steam boilers generating steam at 1400 psig or 260 psig. Steam from the boilers is connected to common steam headers that supply steam–driven electric generating turbines that generate electricity for the site and supply steam at multiple pressures to RED's customers. RED's internal electric grid within the EBP operates at 13.8 kV and is connected with RGE at three locations and is managed under and Interconnection Agreement between the parties. The combined electrical capacity of these three connections with RGE is 41 MW.

a. Schedule D contains single line diagrams of the electric grid within the EBP.

b. The electric system single line diagram includes the three electrical connections with RGE.

c. The major components of RED's steam-electric cogeneration system are :

RED operates boilers at either 1400 psig or 260 psig. The 1400 psig boilers are located in the western end of the site in buildings designated B-321 and B-371. The boilers connect to a common 1400 psig steam header that supplies 4 steam-drive electric turbines which are described in more detail later in this document.

Detail on the 1400 psig Boilers:

- 44 Boiler is a 550 klbs/hr unit located in Building 321 that originally went on-line in 1986 as a tangentially fired coal boiler. The coal was low sulfur compliance coal. As part of RED's plan to exit coal and convert to natural gas this boiler was switched to natural gas as the primary fuel in 2nd quarter 2017. #2 fuel is a backup fuel on this unit.
- 46, 47 and 48 Boilers are each 253 klbs/hr units fired by natural gas only. Oil is not a backup fuel on these units. These three boilers became operational in February, 2018 and are located in Building 371. As shown on the steam single-line diagram these three boilers with 44 Boiler connect to a common header that supplies 4 steam drive electric-generating turbines.

Detail on the 260 psig Boilers:

- 45 Boiler is a 200 klbs/hr unit located in Building 371 with natural gas as the primary fuel. #2 oil is a backup fuel in this unit but based on permitting can only be used due to unavailability of natural gas. This boiler became operational in December, 2017. 45 Boiler connects directly into a 260 psig steam header that supplies steam throughout the EBP to customers and other RED operations.
- Boilers 1, 2, 3, and 4 have a total capacity of 200 klbs/hr and fire #6 Oil. They are located in the EBP site original powerplant B-31 and were installed in the 1950's. The boilers connect to a primary 260 psig steam header located within B-31. RED is targeting to retire these units in spring 2020.

RED operates six steam-driven electric generating turbines with a capacity of 117 MW. Detail on these six units:

- Turbine-Generators (T/G) 41, 42, 43 and 44 are 1400 psig throttle machines located in B-321 in the western end of the site. The units became operational over many years with the first unit 41 T/G becoming operational in 1964 and the last unit 44 T/G becoming operational in 1986. All four T/Gs are rated at 32 MVA and have a nominal generating capacity of 25 MW at a power factor of 80%. As noted previously, their steam supply if from a 1400 psig common header supplied by the natural gas fired boilers described previously. These four units extract steam at either 260 psig or 140 psig and have an exhaust pressure nominally at 10 psig.

- Turbine-Generator (T/G) 17 is a 260 psig throttle machine located in the original powerplant B-31. 17 T/G became operational in 1968 and is a 18.75 MVA machine and has a nominal rating of 15 MW at a power factor of 80%. The unit extracts steam at 70 psig and has an exhaust pressure nominally at 5 psig.
- Turbine-Generator (T/G) 75 is a 5 psig throttle machine located in RED's Chilled Water (refrigeration) building designated B-332. 75 T/G became operational in 2015 by converting a 5 psig to condensing refrigeration unit to a 5 psig to condensing electric generating unit rated at 2 MW. 75 T/G is connected to the 13.8 electrical grid on a distribution cable connected to B-332.

The RED electric grid system one-line diagram, as shown in Schedule D, is based on a bus pair concept linked together by reactor ties to minimize short circuit fault current. The 1400 psig steam throttle generators are connected to bus pairs located in the Western end of the site within B-321. 17 T/G, the 260 psig throttle machine is connected to a bus pair located in the east end of the site near old powerplant B-31 in a main electric building designated B-66. 75 T/G the 2 MW unit is connected to the 13.8 kV distribution cable to B-332. As discussed with RGE technical staff, all RED turbine-generators have automatic voltage control and are typically operated to maintain a MW generation setpoint. The RED Turbine Generator Meter Network is shown in Schedule D.

The three RGE connection points to the RED electrical grid are on bus pairs located in the east end of the site (Ties #1 and #3) and the middle of the site (Tie #2). None of the RGE bus pair connection points are on bus pairs where RED's T/Gs are connected. This means there is not a direct connection from RED electric generation to RGE's electric TIEs. Electrical flow into the bus pairs where the RGE Ties are connected is controlled by a reactor tie associated with the bus pair. As discussed with RGE technical staff the reactor ties connected to bus pairs with RGE Ties #2 and #3 has ratings approximately equal to the rating of the respective RGE Tie. For #1 Tie, the reactor tie rating is higher the than the rating for #1 Tie but as discussed with RGE staff, RED has the ability to control electric flow through #1 Tie to keep it below the #1 Tie rating.

2. RGE

a. Interconnection Facilities Description:

RGE Interconnection Facilities are those facilities located at Stations 403 and 412 identified by the RO&E/CUSTOMER and KODAK/RO&E demarcation lines as shown in Print No. 33198-1 and 33197-1. (Attached in Schedule D)

b. Operating Procedures and Practices.

See Avangrid Network Energy Control Center Switching and Tagging Rules and Procedures attached as Schedule F.

c. RTU Requirements (Section 3.8).

There is a Westronic Wesdac M4 RTU with 32 DI, 8 AI and 6 SBO controls installed at Station 403 and Station 412. (Data points are listed on Schedule H).

3. Points of Interconnection

The Points of Interconnection are the ROE disconnect switches at Station 412 and the separation of RGE's circuit breaker cubical and RED's circuit breaker cubical at Station 403.

4. Interconnection Rights

RED's generators are capable of producing approximately 118 MW of net output during the summer and winter capability periods. However, the maximum output that can be transmitted to the Transmission System pursuant to the Agreement is 41 MW during the summer capability period and winter capability period.

Schedule B

Insurance Requirements

(1) Workers' Compensation Insurance or New York State qualified Self-Insurance in accordance with statutory requirements including Employer's Liability Insurance with limits of not less than $1 million per occurrence and endorsement providing insurance for obligations under the U.S. Longshoremen's and Harbor Workers' Compensation Act and the Jones Act where applicable.

(2) Commercial General Liability Insurance including, but not limited to, bodily injury, property damage, products/completed operations, contractual and personal injury liability with a combined single limit of $2 million per occurrence, $5 million annual aggregate.

(3) Excess (Umbrella) Liability Insurance providing excess general liability, automobile and employers' liability with a combined single limit of $5 million.

(4) Automobile Liability Insurance including owned, non-owned and hired automobiles with combined bodily injury and property damage limits of at least $1 million per occurrence, $2 million aggregate.

Schedule C

Customer's Costs and Expenses for RGE Interconnection Service

Applicable to costs and expenses imposed after the Effective Date in accordance with this Agreement.

Schedule D

One-Line Electrical Diagram

"Schedule D of this Amended Interconnection Agreement Contains Critical Energy Infrastructure Information – Do Not Distribute to Unauthorized Individuals"

[redacted]

RED-Rochester Turbine Generator Meter Network

[redacted]

Schedule E

Bulletin 86-01

Attachments 1-17

(Separate Attachment)

Schedule F

Avangrid Networks Energy Control Center
Switching and Tagging Rules and Procedures

(Separate Attachment)

Schedule G

Metering Equipment Description

Station 403

- GE JKM-5 CURRENT TRANSFORMERS 400:5 PSC APPROVED 0.3 % METERING ACCURACY
- GE JVM-5 VOLTAGE TRANSFORMERS 100:1 PSC APPROVED 0.3% METERING ACCURACY
- JEM MODEL 602 BI-DIRECTIONAL SOLID STATE METER PSC APPROVED 0.3% METERING ACCURACY
- GE DR-87 DEMAND RECORDER W/MODEM READ BY MV-90 DAILY PSC APPROVED DEVICE

Station 412

- GE JKW-200 CURRENT TRANSFORMERS 400:5 PSC APPROVED 0.3% METERING ACCURACY
- GE JVT-200 VOLTAGE TRANSFORMERS 100:1 PSC APPROVED 0.3 % METERING ACCURACY
- JEM MODEL 602 BI-DIRECTIONAL SOLID STATE METER PSC APPROVED 0.3% METERING ACCURACY
- GE DR-87 DEMAND RECORDER W/MODEM READ BY MV-90 DAILY PSC APPROVED DEVICE

Schedule H

RTU Data Points

RTU	Description
403	Sta 403 Battery Monitor
403	Sta 403 1 Trans Mwatts
403	Sta 403 1 Trans Mvars
412	71412 Bkr. Ind.
412	71522 Brk. Ind.
412	74312 Bkr. Ind.
412	1X41252 Brk. Ind.
412	1T41252 Bkr. Ind.
412	1T41242 Bkr. Ind.
412	2T41252 Bkr. Ind.
412	2T41242 Bkr. Ind.
412	Sta 412 Bus 1 Dead
412	Sta 412 Bus 2 Dead
412	Sta 412 Station Major
412	Sta 412 Station Minor
412	Sta 412 1 Trans Mwatts
412	Sta 412 1 Trans Mvars
412	Sta 412 2 Trans Mwatts
412	Sta 412 2 Trans Mvars

Schedule I

Data Reporting

RGE shall have the right to request information regarding the Eastman Business Park electric system as needed for RGE to conduct short circuit and system protection studies and for reporting requirements to the NYISO and the NPCC. RED-Rochester shall provide information regarding the Eastman Business Park electric system no later than sixty (60) days after receipt of a written request therefore from RGE. The information requirements for the Eastman Business Park electrical system used in short circuit and protection studies and for reporting requirements to the NYISO and the NPCC are:

1. equivalent short circuit representation of the Eastman Business Park electrical system, including positive- and zero-sequence impedance data for all generators, reactors, transformers, ground impedances and 13.8 kV circuits between the generator busses and the interties to RGE at Station 403 and Station 412.

2. nameplate data for all generators, including MVA and MW rating for the parameters in which the generators are operated, kV rating, winding configuration, neutral impedances and operating condition (normally on-line, cold standby, etc.), and sub transient reactance (Xd") of each of the generators.

3. one-line relay diagrams for RED-Rochester's substations nearest the intertie points to RGE at Station 403 and Station 412, or for substations elsewhere in the Eastman Business Park electrical system where coordination with protective relays at an RGE substation is required.

4. relay type, CT and PT ratios and relay settings for the protective relays at the RED-Rochester substations nearest the intertie points to RGE at Station 403 and Station 412, or for substations elsewhere in the Eastman Business Park electrical system where coordination with protective relays at an RGE substation is required.

5. underfrequency relay types and settings at the RED-Rochester substations nearest the intertie points to RGE at Station 403 and Station 412.

6. LTC and phase-shifting transformer nameplate data at the RED-Rochester substations nearest the intertie points to RGE at Station 403 and Station 412; specifically MVA, kV and impedance ratings, winding configurations and ground impedance values.

RGE shall provide such information and data as is required for RED-Rochester to coordinate the Eastman Business Park electric system with RGE's system and equipment. RGE shall provide such information and data as is required for RED-Rochester to coordinate the Eastman Business Park electric system with RGE's system and equipment no later than sixty (60) days after receipt of a written request therefore from RED-Rochester.

The information required of the RGE electrical system to be used in RED-Rochester’s short circuit, coordination, and arc flash studies are:

i. relay type, CT and PT ratios and relay settings for the protective relays at RGE's Station 403 and Station 412 to coordinate with protective relays at the Customer Interconnection Facilities; and

ii. one-line relay diagrams for RGE's Station 403 and Station 412 to coordinate with protective relays at the Customer Interconnection Facilities.

iii. RGE fault contribution information including 3-phase MVA and X/R ratio, and single line to ground MVA and X/R ratio at the Points of Interconnection at Station 403 and Station 412.

iv. Specific fault current contribution data through each individual RGE supply line at Station 403 and Station 412 shall be provided. Data for each supply line shall include the 3-phase fault current at rated voltage, the single line to ground fault current at rated voltage, and their respective X/R ratios.

Schedule J

Joint Use Facilities

STATION 412 JOINT USE EQUIPMENT	Location	Owner	Function	Comments
Bus Section #1 Differential Primary Relays	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker to protect Kodak/RGE 34.5kv Bus #1	CTs are on Kodak Breaker 1T41252, and are wired to RGE Relays @ Station 412 (Relays:87B-P1,86B-S1)
Bus Section #1 Differential Secondary Relays	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker to protect Kodak/RGE 34.5kv Bus #1	CTs are on Kodak Breaker 1T41252, and are wired to RGE Relays @ Station 412 (Relays:87B-P2,86B-S1)
Bus Section #2 Differential Primary Relays	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker to protect Kodak/RGE 34.5kv Bus #2	CTs are on Kodak Breaker 2T41252, and are wired to RGE Relays @ Station 412 (Relays:87B-P2,86B-S2)
Bus Section #2 Differential Secondary Relays	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker to protect Kodak/RGE 34.5kv Bus #2	CTs are on Kodak Breaker 2T41252, and are wired to RGE Relays @ Station 412 (Relays:87B-S2,86B-S2)
Bus Section #1 Backup Relay	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker for Bus Differential Backup Protection	Trips all RGE 34.5kv Breakers, including Kodak Breakers (Relays:714-50FD, 743-50FD,86B-P1,86B-S1,62BB-1)
Breaker Section #1 Backup Relay	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker for Stuck Breaker Protection	Trips all RGE 34.5kv Breakers including Kodak Breakers (Relays:714-50FD, 743-50FD,62BB-1,94P)
Bus Section #2 Backup Relay	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker for Bus Differential Backup Protection	Trips all RGE 34.5kv Breakers and Pilot wire, including Kodak Breakers: 1T41252, 2T41252
Breaker Section #2 Backup Relay	STA 412	RGE	Relays connect to RGE Breaker and Kodak Breaker for Stuck Breaker Protection	Trips all RGE 34.5kv Breakers including Kodak Breakers: 1T41252, 2T41252
Battery/Charger	STA 412	RGE	DC supply to RGE and Kodak breakers	RGE Battery and Distribution panel supply DC to Kodak breakers.

STATION 412 JOINT USE EQUIPMENT	Location	Owner	Function	Comments
AC Panel	STA 412	RGE	AC supply for RGE & Kodak Breakers 1T4125, 2T4125	AC for Kodak breaker's Heaters lights & Motors
Bus Section #1 Potential Transformers (Pots) -1 Transformer	STA 412	RGE	Kodak Transformer Voltage meter	RGE Pot K41202 supplies voltage for Kodak 1 Transformer Meter in Bldg. 215, cubicle 238.
Bus Section #1 Potential Transformers (Pots) -2 Transformer	STA 412	RGE	Kodak Transformer Voltage meter	RGE Pot K41211 supplies voltage for Kodak 2 Transformer Meter Kodak 2 Transformer Meter in Station 412
Output Alarm Signals on Kodak transformer differential and breaker operation	STA 412	RGE	Alarm Signals connect to Station 412 Annunciator that indicate when Kodak and RGE breakers operate	Kodak Alarms Signals from transformer differential and breaker operation of 1T4125 and 2T4125 are sent to RGE Annuciator

STATION 403 JOINT USE EQUIPMENT	Location	Owner	Function	Comments
Battery/Primary Charger	STA 403	RGE	DC supply to RGE and Kodak relays	RGE Battery and charger supply DC to Kodak side of the switchgear Cubicles 1,2,3
AC Panel	STA 403	RGE	Provides AC supply for Kodak and RGE breakers	Kodak/RGE BKR AC for Heaters & Motors
Bus Differential Relays	STA 403	RGE	Relays connect to RGE Breaker and Kodak Breaker to protect Kodak/RGE 11.5kVkv Bus Section #1	CTs are on Kodak Breaker 1T40342, and are wired to RGE Relays 87B-1,86B-1 @ Station 403
#1 House Service	STA 403	RGE	Provides 240AC service for Kodak and RGE Switchgear	RGE 11.5kV Distribution Source
Bus Section #1 Potential Transformers (Pots)	STA 403	RGE	Kodak switch board meters	RGE Pots feed Kodak switch board Meters located on Cubicle 3

Schedule E

Bulletin 86-01

BULLETIN 86-01

REQUIREMENTS
FOR THE
INTERCONNECTION OF GENERATION, TRANSMISSION AND END-USER FACILITIES.

Revision Date: October 03, 2011

NYSEG

RG&E

BULLETIN 86-01

REQUIREMENTS FOR THE INTERCONNECTION OF GENERATION, TRANSMISSION AND END-USER FACILITIES.

Revision Date: October 03, 2011

REVIEWED BY: Richard Brown/Bob Raffensperger/Mark Chier

APPROVED BY: Brian A. Conroy

Brian Conroy – Director - Electric Systems Engineering

APPROVED BY: Raymond Kinney

Raymond Kinney – Director – Transmission

1 INTRODUCTION 1-6

1.1 PURPOSE 1-6
1.2 REVISION HISTORY 1-6
1.3 UTILITY CONTACT 1-7

2 DEFINITIONS 2-1

2.1 ACCEPTANCE FOR INTERCONNECTION 2-1
2.2 AFFECTED SYSTEM 2-1
2.3 AFFECTED SYSTEM OPERATOR 2-1
2.4 APPLICABLE LAWS AND REGULATIONS 2-1
2.5 APPLICABLE RELIABILITY COUNCILS 2-1
2.6 APPLICABLE RELIABILITY STANDARDS 2-1
2.7 ATTACHMENT FACILITIES 2-1
2.8 AUTOMATIC DISCONNECT DEVICE 2-2
2.9 BASE CASE 2-2
2.10 BLADE TIP HEIGHT 2-2
2.11 BREACH 2-2
2.12 BREACHING PARTY 2-2
2.13 BULLETIN 2-2
2.14 BUSINESS DAY 2-2
2.15 CALENDAR DAY 2-2
2.16 CEASE TO ENERGIZE 2-2
2.17 CERTIFIED TEST REPORT 2-2
2.18 CLUSTERING 2-3
2.19 COMMERCIAL OPERATION 2-3
2.20 COMMERCIAL OPERATION DATE 2-3
2.21 CONFIDENTIAL INFORMATION 2-3
2.22 COORDINATED ELECTRIC SYSTEM INTERCONNECTION REVIEW (“CESIR”) 2-3
2.23 DEDICATED SERVICE TRANSFORMER OR DEDICATED TRANSFORMER 2-3
2.24 DEFAULT 2-3
2.25 DESIGN TEST 2-3
2.26 DEVELOPER 2-3
2.27 DEVELOPER’S ATTACHMENT FACILITIES 2-4
2.28 DIRECT TRANSFER TRIP (“DTT”) 2-4
2.29 DISCONNECT (VERB) 2-4
2.30 DISCONNECT SWITCH 2-4
2.31 DISPUTE RESOLUTION 2-4
2.32 DRAW-OUT TYPE CIRCUIT BREAKER 2-4
2.33 EFFECTIVE DATE 2-4
2.34 END USER FACILITY 2-4
2.35 ENERGY CONTROL CENTER 2-5
2.36 ENGINEERING & PROCUREMENT (E&P) AGREEMENT 2-5
2.37 ENGINEERING REVIEW 2-5
2.38 ENVIRONMENTAL LAW 2-5
2.39 FARM WASTE AND WIND, NET METER, FARM APPLICANT 2-5

2.40 FERC 2-5
2.41 Final Technical Review 2-5
2.42 Force Majeure 2-5
2.43 Formal Acceptance 2-5
2.44 Generating Facility 2-6
2.45 Generating Facility Capacity 2-6
2.46 Generator-Owner 2-6
2.47 Governmental Authority 2-6
2.48 Hazardous Substances 2-6
2.49 Initial Synchronization Date 2-6
2.50 In-Service Date 2-6
2.51 Interconnection Facilities Study 2-7
2.52 Interconnection Facilities Study Agreement 2-7
2.53 Interconnection Feasibility Study 2-7
2.54 Interconnection Feasibility Study Agreement 2-7
2.55 Interconnection Request 2-7
2.56 Interconnection Study 2-7
2.57 Interconnection System Reliability Impact Study (“SRIS”) 2-7
2.58 Interconnection System Reliability Impact Study Agreement 2-8
2.59 IPP 2-8
2.60 IRS 2-8
2.61 Islanding 2-8
2.62 Large Generating Facility 2-8
2.63 Large Generator Interconnection Procedures (“LGIP”) 2-8
2.64 Large Generator Interconnection Agreement (“LGIA”) 2-8
2.65 Loss 2-8
2.66 Material Modification 2-9
2.67 Merchant Generator 2-9
2.68 Merchant Transmission Facility 2-9
2.69 Metering Equipment 2-9
2.70 Minimum Interconnection Standard 2-9
2.71 NERC 2-9
2.72 Net Metering 2-9
2.73 Network Access Interconnection Service 2-10
2.74 Notice of Dispute 2-10
2.75 NPCC 2-10
2.76 NYISO 2-10
2.77 NYSDPS 2-10
2.78 NYSEG 2-10
2.79 OATT 2-10
2.80 OC 2-10
2.81 Optional Interconnection Study 2-10
2.82 Optional Interconnection Study Agreement 2-11
2.83 Parallel Operation 2-11
2.84 Party or Parties 2-11
2.85 Point of Change of Ownership 2-11

2.86 POINT OF COMMON COUPLING 2-11
2.87 POINT OF INTERCONNECTION 2-11
2.88 PRELIMINARY TECHNICAL REVIEW 2-11
2.89 PROTECTION SYSTEM IMPACT STUDY 2-11
2.90 PROTECTIVE DEVICE 2-11
2.91 QUEUE POSITION 2-12
2.92 REASONABLE EFFORTS 2-12
2.93 REMOTE TERMINAL UNIT (“RTU”) 2-12
2.94 REQUIRED OPERATING RANGE 2-12
2.95 RGE 2-12
2.96 SCADA (“SUPERVISORY CONTROL AND DATA ACQUISITION”) 2-12
2.97 SCOPING MEETING 2-12
2.98 SERVICES TARIFF 2-13
2.99 SMALL GENERATOR INTERCONNECTION PROCEDURES (“SGIP”) 2-13
2.100 SMALL GENERATOR INTERCONNECTION AGREEMENT (“SGIA”) 2-13
2.101 SIR 2-13
2.102 SITE CONTROL 2-13
2.103 SOLAR, WIND AND MICRO CHP/FUEL CELL, NET METER, RESIDENTIAL APPLICANT 2-13
2.104 SOLAR AND WIND, NET METER, NON-RESIDENTIAL APPLICANT 2-13
2.105 STAND ALONE SYSTEM UPGRADE FACILITIES 2-14
2.106 SYSTEM PROTECTION FACILITIES 2-14
2.107 TARIFF 2-14
2.108 TPAS 2-14
2.109 TRANSMISSION OWNER 2-14
2.110 TRANSMISSION OWNER’S ATTACHMENT FACILITIES 2-14
2.111 TRIAL OPERATION 2-15
2.112 UTILITY GRADE RELAY 2-15
2.113 VERIFICATION TEST 2-15

3 APPLICATION AND REVIEW PROCESS 3-1

3.1 GENERAL 3-1
3.2 DISTRIBUTED GENERATION RATED 2 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS 3-1
3.2.1 Introduction 3-1
3.2.2 Application Process Steps 3-2
- *Proposed three line diagram of the generation system showing the interconnection of major electrical components within the system. Proposed equipment ratings clearly needs to indicate: 3-7*
- *Electrical studies as requested by the utility to demonstrate that the design is within acceptable limits, inclusive and limited to the following: system fault, relay coordination, flicker, voltage drop, and harmonics. 3-7*

3.3 INDEPENDENT POWER PRODUCER GENERATION RATED GREATER THAN 2 MW AND LESS THAN OR EQUAL TO 20 MW THAT DOES NOT FALL UNDER THE SMALL GENERATION INTERCONNECTION PROCEDURE OF THE NYISO, ... 3-10
3.3.1. Introduction 3-10

3.3.2. Engineering Review Process ... *3-11*
3.4 GENERATING FACILITY, OR MERCHANT TRANSMISSION FACILITY INTERCONNECTING TO THE NEW YORK STATE TRANSMISSION SYSTEM UNDER THE LARGE GENERATION INTERCONNECTION PROCEDURES OR THE SMALL GENERATION INTERCONNECTION PROCEDURES. ... 3-12

4 INFORMATION REQUIREMENTS ... 4-1

4.1 UTILITY FORM NB 232* ... 4-1
4.1.1 Developer Information ... *4-1*
4.1.2 Generator Information ... *4-1*
4.1.3 Merchant Transmission Interconnection Information ... *4-2*
4.1.4 End User Facility Interconnection Information ... *4-2*
4.1.5 General Information ... *4-2*
4.1.6 Remarks ... *4-2*
4.2 APPLICATION FORM* ... 4-3
4.3 PROJECT SCHEDULE ... 4-3
4.4 SITE PLAN* ... 4-3
4.5 DESCRIPTION OF OPERATION* ... 4-3
4.6 ONE LINE ELECTRICAL DIAGRAM OF COMPLETE FACILITY* ... 4-3
4.7 ONE LINE RELAY DIAGRAM* ... 4-3
4.8 THREE LINE RELAY OR AC ELEMENTARY DIAGRAM(S)* ... 4-4
4.9 ELEMENTARY CONTROL OR DC ELEMENTARY CONTROL DIAGRAM(S) ... 4-4
4.10 GENERATOR, EXCITER AND GOVERNOR INFORMATION SHEETS* ... 4-4
4.11 EQUIPMENT NAMEPLATE DATA AND ELECTRICAL RATINGS ... 4-4
4.12 PROPOSED RELAY TYPES AND SETTINGS FOR FAULT ISOLATION PROTECTION SCHEMES ... 4-5
4.13 TELEMETERING INFORMATION (WHEN APPLICABLE) ... 4-5
4.14 PROTECTIVE RELAY COMMUNICATIONS AND MONITORING SYSTEMS INFORMATION (WHEN APPLICABLE) ... 4-6
4.15 METHOD OF EXCITATION ... 4-6
4.16 MINIMUM SITE LOAD WITHOUT GENERATION ON LINE* ... 4-6
4.17 GENERATION SATURATION CURVE ... 4-6
4.18 EXCITER SATURATION CURVES ... 4-6
4.19 BLOCK DIAGRAMS ... 4-6
4.20 REGULATORY FILINGS, IMPACT STATEMENTS, LICENSE APPLICATIONS AND OTHER PERMIT APPLICATIONS ... 4-7
4.21 ADDITIONAL INFORMATION ... 4-7

5 UTILITY SYSTEM MODIFICATIONS ... 5-1

5.1 GENERAL ... 5-1
5.2 PRELIMINARY COST ESTIMATE ... 5-1
5.3 FINAL COST ESTIMATE ... 5-1
5.4 ENGINEERING, DESIGN AND CONSTRUCTION ... 5-1
5.5 REGULATORY APPROVALS AND PERMITS ... 5-2
5.6 INSTALLATION AND TESTING ... 5-2
5.7 AFFECTED SYSTEMS ... 5-2

6 ELECTRICAL INTERCONNECTION REQUIREMENTS......... 6-1
6.1 NEW YORK STATE STANDARDIZED INTERCONNECTION REQUIREMENTS FOR NEW DISTRIBUTED GENERATION 2 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS 6-1
6.1.1 Design Requirements 6-1
6.1.2 Operating Requirements 6-7
6.1.3 Dedicated Transformer 6-8
6.1.4 Circuit Breakers and Other Interrupting Devices 6-8
6.1.5 Insulators 6-9
6.1.6 Disconnect Switch 6-9
6.1.7 Power Quality 6-10
6.1.8 Power Factor 6-10
6.1.9 Islanding 6-11
6.1.10 Equipment Certification *6-11*
6.1.11 Verification Testing *6-12*
6.2 ELECTRICAL INTERCONNECTION REQUIREMENTS FOR INDEPENDENT POWER PRODUCER GENERATION RATED GREATER THAN 2 MW, MERCHANT TRANSMISSION LINES AND END USER FACILITIES. 6-12
6.2.1 General 6-12
6.2.2 System Design Requirements for Independent Power Producer Generation Rated Greater than 2 MW, Merchant Transmission Lines and End User Facilities. *6-14*
6.2.3 Metering 6-23
6.2.4 Data Telemetering 6-27
6.3 PROTECTIVE RELAY COMMUNICATIONS AND MONITORING SYSTEMS FOR INDEPENDENT POWER PRODUCER GENERATION RATED GREATER THAN 2 MW, MERCHANT TRANSMISSION LINES AND END USER FACILITIES. 6-29
6.3.1 Terminal Equipment 6-29
6.3.2 Communications Media 6-31
6.3.3 Other Utilities 6-34

7 INSPECTION, CERTIFICATION, TESTING, AND MAINTENANCE REQUIREMENTS.. 7-1
7.1 INSPECTION AND CERTIFICATION REQUIREMENTS 7-1
7.2 TEST REQUIREMENTS 7-1
7.2.1 Initial Inspection and Tests 7-1
7.2.2 Periodic Tests 7-2
7.2.3 Tests to be Performed 7-2

8 ACCEPTANCE FOR INTERCONNECTION.. 8-1
8.1 REQUIREMENTS FOR INTERCONNECTION 8-1
8.1.1 Protection Design 8-1
8.1.2 PE Certification 8-1
8.1.3 Certificate of Inspection 8-1
8.1.4 Utility Inspection 8-1
8.1.5 Testing Completion 8-1

8.1.6 Safety and Operating Procedures ... 8-1
8.7.1 Other ... 8-1
8.2 INTERCONNECTION/SYNCHRONIZATION OF DEVELOPER'S FACILITY ... 8-1
8.3 MAINTENANCE REQUIREMENTS ... 8-2
8.4 DEVELOPER'S SYSTEM MODIFICATIONS ... 8-2
9 ATTACHMENTS ... 9-1

1 INTRODUCTION

1.1 PURPOSE

The purpose of this Bulletin is to document the Utility's application and review process, and technical requirements for Developers with generating sources operating in parallel with the Utility system, Merchant transmission line interconnections, and large end user interconnections to serve loads. These requirements have been developed based on (i) regulatory requirements as set forth by the NYSDPS and/or FERC, (ii) the NYISO guidelines, and (iii) typical Utility industry design, operating procedures and safety practices in order to ensure the safety of Utility personnel and equipment, Utility customers and the general public.

1.2 REVISION HISTORY

Date	Revision Number	Change	Reference Sections
5/31/2005	NA	Adoption of Revision History	NA
7/7/2009	2.0	Updated NYISO Procedures, updated SIRS 7 and 11 step process. Added NERC security requirements	3.2, 3.3, 3.4, 6.1.1.6, 6.3
11/5/2009	3.0	Added Reviewed and Approval signature lines	Page 2
12/22/2009	4.0	Adding Revision History Adding more end user and merchant transmission interconnection information	1.2, 2.x,
9/1/2010	5.0	Accommodating NERC feedback from 2009 compliance filing.	Index, 2.10, 3.1, 4.7, 4.8, 5.7, 6.2, 6.3, Attachment 1

4/13/2011	**6.0**	**Updated SIRS 7 and 11 step process. Revised generator disconnect switch requirements**	**3.2 , 6.1.6**

1.3 UTILITY CONTACT

All correspondence regarding interconnections shall be directed to the following:

Manager Programs/Projects
Electric Transmission Services
NYSEG/RGE
New York State Electric & Gas Corporation
James A. Carrigg Center
Kirkwood Industrial Park - Corporate Drive
P.O. Box 5224
Binghamton, NY 13902-5224

Telephone: (607) 762-7606, (607)762-8073)
Facsimile: (607) 762-8666

2 DEFINITIONS

Whenever used in this Bulletin with initial capitalization, the following terms shall have the meanings specified in this Section 2. Terms used in this Bulletin with initial capitalization that are not defined in this Section 2 shall have meanings specified in Attachment S of the NYISO OATT.

2.1 Acceptance for Interconnection

Written acceptance by the Utility; contingent upon the Utility's satisfaction with the inspection of the Developer's facilities, testing of the Developer's protection equipment, and the fulfillment of all contractual obligations required prior to the interconnection of the Developer's facility.

2.2 Affected System

An electric system other than the transmission system owned, controlled or operated by the NYISO or the Transmission Owner that may be affected by the proposed interconnection.

2.3 Affected System Operator

The entity that operates the Affected System.

2.4 Applicable Laws and Regulations

All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority, including but not limited to Environmental Law.

2.5 Applicable Reliability Councils

The NERC, the NPCC and the NYSRC.

2.6 Applicable Reliability Standards

The requirements and guidelines of the Applicable Reliability Councils, and the Transmission District, to which the Developer’s Large Facility is directly interconnected, as those requirements and guidelines are amended and modified and in effect from time to time; provided that no Party shall waive its right to challenge the applicability or validity of any requirement or guideline as applied to it in the context of the large Facility Interconnection Procedures.

2.7 Attachment Facilities

The Transmission Owner’s Attachment Facilities and the Developer’s Attachment Facilities. Collectively, Attachment Facilities include all facilities and equipment between the Large Generating Facility, End User Facility, or Merchant Transmission Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Facility to the New York State Transmission System. Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities or System Upgrade Facilities.

2.8 Automatic Disconnect Device

An electronic or mechanical switch used to isolate a circuit or piece of equipment from a source of power without the need for human intervention.

2.9 Base Case

The base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the NYISO, Transmission Owner or Developer; described in Section 2.3 of the Large Facility Interconnection Procedures.

2.10 Blade Tip Height

The distance from the ground to the highest point possible for a wind turbine's rotor and blade assembly.

2.11 Breach

The failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

2.12 Breaching Party

A Party that is in Breach of the Standard Large Generator Interconnection Agreement.

2.13 Bulletin

Bulletin 86-01, "REQUIREMENTS FOR THE INTERCONNECTION OF GENERATION, TRANSMISSION AND END-USER FACILITIES".

2.14 Business Day

Monday through Friday, excluding federal holidays.

2.15 Calendar Day

Any day including Saturday, Sunday or a federal holiday.

2.16 Cease to Energize

Cessation of energy flow capability.

2.17 Certified Test Report

A report generated by a recognized commercial testing company and signed by a licensed electrician or professional engineer.

2.18 Clustering

The process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Reliability Impact Study.

2.19 Commercial Operation

The status of a Facility that has commenced generating or transmitting electricity for sale, excluding electricity generated or transmitted during Trial Operation.

2.20 Commercial Operation Date

The date on which the Facility commences Commercial Operation as agreed to by the Parties pursuant to either the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.21 Confidential Information

Any information that is defined as confidential by either the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.22 Coordinated Electric System Interconnection Review ("CESIR")

Any studies performed by utilities to ensure the safety and reliability of the electric grid with respect to the interconnection of distributed generation as discussed in this Bulletin.

2.23 Dedicated Service Transformer or Dedicated Transformer

A transformer with a secondary winding that serves only one customer.

2.24 Default

The failure of a Party in Breach of the standard Large Facility Interconnection Agreement or the Small Facility Interconnection Agreement to cure such Breach in accordance with the appropriate Interconnection Agreement.

2.25 Design Test

A test performed on protective equipment to ensure that devices and systems used in a proposed application meet the necessary technical and functional requirements.

2.26 Developer

An individual, company, corporation, limited partnership, etc., developing a project to be interconnected to the Utility's system.

2.27 Developer’s Attachment Facilities

All facilities and equipment, as identified in Large Facility Interconnection Agreement or the Small Facility Interconnection Agreement, that are located between the Facility or Merchant Transmission Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility, End User, or Merchant Transmission Facility to the New York State Transmission System. Developer’s Attachment Facilities are sole use facilities.

2.28 Direct Transfer Trip (“DTT”)

Remote operation of a circuit breaker by means of a communication channel.

2.29 Disconnect (verb)

To isolate a circuit or equipment from a source of power. If isolation is accomplished with a solid state device, “Disconnect” shall mean to cease the transfer of power.

2.30 Disconnect Switch

A mechanical device used for isolating a circuit or equipment from a source of power.

2.31 Dispute Resolution

The procedures described in the Large Facility Interconnection Procedures or the Small Facility Interconnection Procedures for resolution of a dispute between Parties.

2.32 Draw-out Type Circuit Breaker

Circuit breakers that are disconnected by physically separating, or racking, the breaker assembly away from the switchgear bus.

2.33 Effective Date

The date on which the Large Generator Interconnection Agreement or the Small Generator Interconnection Agreement becomes effective upon execution by the Parties, subject to acceptance by the Commission, or filed unexecuted, upon the date specified by the Commission.

2.34 End User Facility

A utility customer interconnecting to a transmission line in order to serve load.

2.35 Energy Control Center

A Utility control center whose purpose is to monitor and operate the electric transmission or distribution center.

2.36 Engineering & Procurement (E&P) Agreement

An agreement that authorizes Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

2.37 Engineering Review

Preliminary Technical Review and/or Final Technical Review.

2.38 Environmental Law

Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

2.39 Farm Waste and Wind, Net Meter, Farm Applicant

A farm applicant who is proposing to install a farm waste anaerobic digester generating system, not to exceed 1,000 kW, or farm wind not exceed 500kW at a farm, per the requirements of New York State Public Service Law §66-j.

2.40 FERC

Federal Energy Regulatory Commission.

2.41 Final Technical Review

A detailed review of the Customer-Generator's internal AC and DC elementary and control design, protection system and proposed device settings to determine if the proposed system will respond appropriately to Utility system abnormalities, such as Utility short circuits.

2.42 Force Majeure

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, in any order, regulation or restriction imposed by government, military or lawfully established civilian authorities, or any other cause beyond the Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

2.43 Formal Acceptance

Written acceptance by the Utility; contingent upon the Utility's review of and satisfaction with the complete information package to be provided by the Developer as specified in this Bulletin.

2.44 *Generating Facility*

The Developer's device for the production of electricity identified in the Interconnection Request, but shall not include the Developer's Attachment Facilities.

2.45 *Generating Facility Capacity*

The net seasonal capacity of the Generating Facility and the aggregate net seasonal capacity of the Generating Facility where it includes multiple energy production devices.

2.46 *Generator-Owner*

An applicant who is proposing to install and operate on-site power generation equipment in parallel with the Utility grid per the requirements of this Bulletin.

2.47 *Governmental Authority*

Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over any of the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Developer, NYISO Transmission Owner, or any Affiliate thereof.

2.48 *Hazardous Substances*

Any chemicals, materials, or substances defined as or included in the definition of "hazardous substances", "hazardous waste", "hazardous materials", "hazardous constituents", "restricted hazardous materials", extremely hazardous substances", "toxic substances", radioactive substances", "contaminants", "pollutants", "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

2.49 *Initial Synchronization Date*

The date upon which the Generating Facility, End-User Facility, or Merchant Transmission Facility is initially synchronized and upon which Trial Operation begins.

2.50 *In-Service Date*

The date upon which the Developer reasonably expects it will be ready to begin use of the Transmission Owner's Attachment Facilities to obtain back feed power.

2.51 Interconnection Facilities Study

A study conducted by the NYISO or a third party consultant for the Developer to determine a list of facilities (including Transmission Owner's Attachment Facilities and System Upgrade Facilities as identified in the Interconnection System Reliability Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility or Merchant Transmission Facility with the New York State Transmission System. The scope of the study is defined in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.52 Interconnection Facilities Study Agreement

The form of agreement is contained in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

2.53 Interconnection Feasibility Study

A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility or Merchant Transmission Facility to the New York State Transmission System, the scope of the study is defined in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.54 Interconnection Feasibility Study Agreement

The form of agreement is contained in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

2.55 Interconnection Request

Developer's request, in the form is contained in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility or Merchant Transmission Facility to the New York State Transmission System, or to increase capacity of, or make a material modification to the operating characteristics of, an existing Generating Facility or Merchant Transmission Facility that is interconnected with the New York State Transmission System.

2.56 Interconnection Study

Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Reliability Impact Study, and the Interconnection Facilities Study described in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.57 Interconnection System Reliability Impact Study ("SRIS")

An engineering study that evaluates the impact of the proposed Generation Facility or Merchant Transmission Facility on the safety and reliability of the

New York State Transmission System and, if applicable, an Affected System, to determine what Attachment Facilities and System Upgrade Facilities are needed for the proposed Generation Facility or Merchant Transmission Facility of the Developer to connect reliably to the New York State Transmission System in a manner that meets the NYISO Minimum Interconnection Standard. The scope of the SRIS is defined in Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures.

2.58 Interconnection System Reliability Impact Study Agreement

The form of agreement contained in the Large Generator Interconnection Procedures or the Small Generator Interconnection Procedures for conducting the System Reliability Impact Study.

2.59 IPP

Independent Power Producer.

2.60 IRS

Internal Revenue Service.

2.61 Islanding

A condition in which a portion of the Utility system that contains both load and distribution generation is isolated from the remainder of the Utility system. [Adopted from IEEE Std. 929]

2.62 Large Generating Facility

A Generating Facility having a Generating Facility Capacity of more than 20 MW.

2.63 Large Generator Interconnection Procedures ("LGIP")

The interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility or Merchant Transmission Facility that are included in Attachment X of the NYISO OATT.

2.64 Large Generator Interconnection Agreement ("LGIA")

The form of interconnection agreement applicable to a Interconnection Request pertaining to a Large Generating Facility, that is included in Attachment X to the NYISO OATT.

2.65 Loss

Any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Indemnified Party's performance or non-performance of its obligations under the

Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

2.66 Material Modification

Those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

2.67 Merchant Generator

A generator that sells its energy and/or capacity into the market or to an entity other than the Utility.

2.68 Merchant Transmission Facility

Developer's device for the transmission of electricity identified in the Interconnection Request, but shall not include Developer's Attachment Facilities. Merchant Transmission Facilities shall be those for which the Developer intends to receive approval from the FERC to charge market-based rates. Merchant Transmission Facilities shall not include upgrades or additions to the New York State Transmission System for which the owner does not have market-based rate authority.

2.69 Metering Equipment

All metering equipment installed or to be installed at the Generating Faclility or Merchant Transmission Facility pursuant to the Large Generator Interconnection Agreement or the Small Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

2.70 Minimum Interconnection Standard

The reliability standard that must be met by any Generating Facility, or Merchant Transmission Facility, proposing to interconnection to the New York State Transmission System. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. The Standard does not impose any deliverability requirement on the proposed interconnection.

2.71 NERC

North American Electric Reliability Corporation or its successor.

2.72 Net Metering

The term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period. Eligibility and requirements for net metering are defined in New York State Public Service Law §66-j and §66-l.

2.73 Network Access Interconnection Service

The service provided by the NYISO to interconnect the Developer's Generating Facility or Merchant Transmission Facility to the New York State Transmission System in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive electric energy and capacity from the Generating Facility or Merchant Transmission Facility at the Point of Interconnection, pursuant to the terms of the NYISO OATT.

2.74 Notice of Dispute

A written notice of dispute or claim that arises out of or in connection with the Large Generator Interconnection Procedures, the Small Generator Interconnection Procedures, or the Standard Large Generator Interconnection Agreement, or the Standard Small Generator Interconnection Agreement, or its performance.

2.75 NPCC

Northeast Power Coordinating Council or its successor.

2.76 NYISO

New York Independent System Operator, Inc.

2.77 NYSDPS

New York State Department of Public Service, also known as the Public Service Commission.

2.78 NYSEG

New York State Electric & Gas Corporation.

2.79 OATT

Open Access Transmission Tariff.

2.80 OC

NYISO Operating Committee.

2.81 Optional Interconnection Study

A sensitivity analysis based on assumptions specified by the Developer in the Optional Interconnection Study Agreement.

2.82 Optional Interconnection Study Agreement

The form of agreement contained in the Large Generator Interconnection Procedures, or the Small Generator Interconnection Procedures for conducting the Optional Interconnection Study.

2.83 Parallel Operation

All electric power generation that is connected to a Utility substation, transmission and/or distribution facility that is part of the Utility electric system. **In accordance with IEEE 1547, g**eneration intended to be interconnected to the Utility system for 0.1 seconds or longer will be considered to be in Parallel Operation.

2.84 Party or Parties

NYISO, Transmission Owner, or Developer or any combination thereof.

2.85 Point of Change of Ownership

The point, as set forth in Large Generator Interconnection Agreement, or the Small Generator Interconnection Agreement, where the Developer's Attachment Facilities connect to the Transmission Owner's Attachment Facilities.

2.86 Point of Common Coupling

The point at which the interconnection between the electric Utility and the customer interface occurs. Typically, this is the customer side of the Utility revenue meter.

2.87 Point of Interconnection

The point, as set forth in the Large Generator Interconnection Agreement, or the Small Generator Interconnection Agreement, where the Attachment Facilities connect to the New York State Transmission System.

2.88 Preliminary Technical Review

A review of the generator-owner's proposed system capacity, impact of the proposed generation on the Utility system, system characteristics and general system regulation to determine if the interconnection is viable.

2.89 Protection System Impact Study

A study of the impact on the Utility protection system, short circuits on the Utility electric system and ferroresonant overvoltage studies that are performed on the Utility electrical system during the SRIS.

2.90 Protective Device

A device that continuously monitors a designated parameter related to the operation of the generation system that operates if preset limits are exceeded.

2.91 Queue Position

The order of a valid NYISO Interconnection Request, relative to all other pending valid NYSIO Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection request by the NYISO.

2.92 Reasonable Efforts

With respect to an action required to be attempted or taken by a Party under the Large Generator Interconnection Procedures, or the Small Generator Interconnection Procedures, or the Large Generator Interconnection Agreement, or the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

2.93 Remote Terminal Unit ("RTU")

A device located in a substation or generating station used to monitor various electrical quantities and/or status of electrical equipment that is telecommunicated to an operator at a Utility Energy Control Center, and/or to provide control functions of remote equipment to the operator.

2.94 Required Operating Range

The range of magnitudes of the utility system voltage or frequency where the generator-owner's equipment, if operating, is required to remain in operation for the purposes of compliance with UL 1741 Excursions outside these ranges must result in the automatic disconnection of the generation within the prescribed time limits.

2.95 RGE

Rochester Gas & Electric Corporation.

2.96 SCADA ("Supervisory Control And Data Acquisition")

The system used to telemeter analog and status points of data collected by RTUs to the Utility Energy Control Center.

2.97 Scoping Meeting

The meeting between representatives of the Developer, NYISO and Transmission Owner conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine potential feasible Points of Interconnection.

2.98 Services Tariff

The NYISO Market Administration and Control Area Tariff, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff thereto.

2.99 Small Generator Interconnection Procedures (“SGIP”)

The interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility or Merchant Transmission Facility that are included in Attachment Z of the NYISO OATT.

2.100 Small Generator Interconnection Agreement (“SGIA”)

The form of interconnection agreement applicable to a Interconnection Request pertaining to a Generating Facility, that is included in Attachment Z to the NYISO OATT.

2.101 SIR

The New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators Rated 2 MW or Less Connected in Parallel with Utility Distribution Systems.

2.102 Site Control

Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Large Generating Facility or Merchant Transmission Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Developer and the entity having the right to sell, lease or grant Developer the right to possess or occupy a site for such purpose.

2.103 Solar, Wind and Micro CHP/Fuel Cell, Net Meter, Residential Applicant

A residential applicant who is proposing to install a photovoltaic, wind and/or Micro CHP/Fuel Cell generating system, not to exceed 25 kW, in an owner occupied residence per the requirements of New York State Public Service Law §66-j and §66-l

2.104 Solar and Wind, Net Meter, Non-Residential Applicant

A non residential applicant who is proposing to install a photovoltaic and/or wind generating system, greater then 25kW but not to exceed 2MW, in an owner occupied residence per the requirements of New York State Public Service Law §66-j and §66-l

2.105 Stand Alone System Upgrade Facilities

System Upgrade Facilities that a Developer may construct without affecting day-to-day operations of the New York State Transmission System during their construction. NYISO, the Transmission Owner and the Developer must agree as to what constitutes Stand Alone System Upgrade Facilities and identify them in the Large Generator Interconnection Agreement, or the Small Generator Interconnection Agreement.

2.106 System Protection Facilities

The equipment, including necessary protection signal communications equipment, required to (1) protect the New York State Transmission System from faults or other electrical disturbances occurring at the Generating Facility or Merchant Transmission Facility or (2) protect the Generating Facility or Merchant Transmission Facility from faults or other electrical system disturbances occurring on the New York State Transmission System or on other delivery systems or other generating systems to which the New York State Transmission System is directly connected.

2.107 Tariff

The NYISO Open Access Transmission Tariff (“OATT”) , as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

2.108 TPAS

NYISO Transmission Planning Advisory Subcommittee.

2.109 Transmission Owner

The public utility or authority (or its designated agent) that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns leases or otherwise possesses an interest in the portion of the New York State Transmission System at the Point of Interconnection and (iii) is a Party to the Large Generator Interconnection Agreement or the Small Generator Interconnection Agreement.

2.110 Transmission Owner’s Attachment Facilities

All facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in the Large Generator Interconnection Agreement or the Small Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner’s Attachment Facilities are sole use facilities and shall not include Stand Alone Upgrade Facilities or System Upgrade Facilities.

2.111 Trial Operation

The period during which Developer is engaged in on-site test operations and commissioning of the Generating Facility or Merchant Transmission Facility prior to Commercial Operation.

2.112 Utility Grade Relay

A relay that is constructed to comply with, as a minimum, the most current version of the following standards for non-nuclear facilities:

Standard	Conditions Covered
ANSI/IEEE C37.90	Usual Service Condition Ratings - Current and Voltage Maximum design for all relay ac and dc auxiliary relays Make and carry ratings for tripping contacts Tripping contacts duty cycle Dielectric tests by manufacturer Dielectric tests by user
ANSI/IEEE C37.90.1	Surge Withstand Capability (SWC) Fast Transient Test
IEEE C37.90.2	Radio Frequency Interference
IEEE C37.98	Seismic Testing (fragility) of Protective and Auxiliary Relays
ANSI C37.2	Electric Power System Device Function Numbers
IEC 255-21-1	Vibration
IEC 255-22-2	Electrostatic Discharge
IEC 255-5	Insulation (Impulse Voltage Withstand)

2.113 Verification Test

A test performed upon initial installation and repeated periodically to determine if there is continued acceptable performance.

3 APPLICATION AND REVIEW PROCESS

3.1 General

Before a Developer is allowed to install and operate any facility in parallel with the Utility system, the Developer shall submit design and operating information for the proposed facility to the Utility for its review and Formal Acceptance in accordance with the applicable application and review process described in this Bulletin.

The Utility's review and acceptance of the Developer's proposed facility and protection design and operating information for the proposed facility shall not be construed as confirming or endorsing the design, or as any warranty of safety, desirability, or reliability of any of the Developer's facilities.

The Developer will be responsible for all Utility costs incurred during the Application and Review Process as set forth in this Bulletin.

All wind turbine installations must be set back from the edge of a transmission line right of way a distance of at least 1.5 times the Blade Tip Height, or more as required by the local building and zoning ordinances. All wind turbine installations must be set back from all distribution line conductors and structures a distance of at least 1.5 times the Blade Tip Height, or more as required by the local building and zoning ordinances. No construction of wind turbine towers will be allowed until these setback requirements are met, this may include any relocation of utility lines and structures or the burying of utility lines.

All wind turbines installed in the vicinity of gas pipelines shall design their ground grids to be in full conformance with IEEE 80 standards. Developer shall test the ground grids for all turbines within 600 feet of a metal gas pipeline on a yearly basis and provide the results of the testing in a report to the Utility.

3.2 Distributed Generation Rated 2 MW or Less Connected in Parallel with Utility Distribution Systems

3.2.1 Introduction

This section provides a framework for processing applications to:

- interconnect new distributed generation facilities with a nameplate rating of 2 MW or less [aggregated on the customer side of the point of common coupling (PCC)], and

- review any modifications affecting the interface at the PCC to existing distributed generation facilities with a nameplate rating of 2 MW or less (aggregated on the customer side of the PCC) that have been interconnected to the utility distribution system and where an existing contract between the applicant and the utility is in place.

Generation neither designed to operate, nor operating, in parallel with the utility's electrical system is not subject to these requirements. This section will ensure that applicants are aware of the technical interconnection requirements and utility interconnection policies and practices. This section will also provide applicants with an understanding of the process and information required to allow utilities to review and accept the applicants' equipment for interconnection in a reasonable and expeditious manner.

The time required to complete the process will reflect the complexity of the proposed project. Projects using previously submitted designs certified per the requirements of Section II.H will move through the process more quickly, and several steps may be satisfied with an initial application depending on the detail and completeness of the application and supporting documentation submitted by the applicant. Applicants submitting systems utilizing certified equipment however, are not exempt from providing utilities with complete design packages necessary for the utilities to verify the electrical characteristics of the generator systems, the interconnecting facilities, and the impacts of the applicants' equipment on the utilities' systems.

The application process and the attendant services must be offered on a non-discriminatory basis. The utilities must clearly identify their costs related to the applicants' interconnections, specifically those costs the utilities would not have incurred but for the applicants' interconnections. The utilities will keep a log of all applications, milestones met, and justifications for application-specific requirements. The applicants are to be responsible for payment of the utilities' costs, as provided for herein.

3.2.2 Application Process Steps

STEP 1: Initial Communication from the Potential Applicant

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project

Technical staff from the utility discusses the scope of the interconnection with the potential applicant (either by phone or in person) to determine what specific information and documents (such as an application, contract, technical requirements, specifications, listing of qualified type-tested equipment/systems, applicable rate schedules, and metering requirements) will be provided to the potential applicant. The preliminary technical feasibility of the project at the proposed location may also be discussed at this time. All such information and a copy of the standardized interconnection requirements (SIR) must be sent to the applicant within three (3) business days following the initial communication from the potential applicant, unless the potential applicant indicates otherwise. A utility representative will be designated to serve as the single point of contact for the applicant (unless the utility informs the applicant otherwise) in coordinating the potential applicant's project with the utility.

STEP 3: Potential Applicant Files an Application

The potential applicant submits an application package to the utility. A complete application package will consist of (1) a letter of authorization by the customer (if the applicant is an agent for the customer), (2) the standard single page application form completed and signed by the applicant, (3) a signed copy of the standardized contract, (4) a three line diagram for the system identifying the manufacturer and model number of the equipment(s), (5) a copy of the manufacturer's data sheet for the equipment(s), (6) a copy of the manufacturers verification test procedure(s) and (7) a copy of the equipment(s) certification to UL 1741 (November 2005 revision) if applicable. The equipment(s) will be considered acceptable by the utility if they meet the requirements of Section II.H. If the application is not complete, then within five (5) business days of receipt of the application package the utility will notify the applicant by email, fax, or other form of written communication, and explain the deficiencies. If the proposed system meets the SIR technical requirements the utility will return a signed and executed standardized contract to the applicant within ten (10) business days of receiving the application and the applicant may proceed with the installation. If the proposed system does not meet the SIR technical requirements, then the utility will so notify the applicant within ten (10) business days of receiving the application by email, fax, or other form of written communication and explain the technical issues or problems.

Maximum Expense for Dedicated Transformer and Other Safety Equipment for Net Metered Customers (25kW or Less)

Generator Type	Generator Size	Maximum Equipment Responsibility
Micro CHP/Fuel Cell	Less than or equal to 10 kW	$350
Solar	Less than or equal to 25 kW	$350
Wind	Less than or equal to 25 kW	$750

STEP 4: System Installation

The applicant will install the system according to the utility accepted design and the equipment manufacturer's requirements. All inverter based systems will be allowed to interconnect to the utility system for a period not to exceed two hours, for the sole purpose of assuring proper operation of the installed equipment.
For net metered systems as defined in Section II.A.6, any modifications related to existing metering configurations to allow for net metering shall be completed by the utility prior to Step 5. The utility shall complete the necessary metering changes within ten (10) business days of receiving request from the applicant.

STEP 5: The Applicant's Facility is Tested in Accordance with the Standardized Interconnection Requirements.

Verification testing will be performed by the applicant in accordance with the written verification test procedure provided by the equipment manufacturer. The verification testing will be conducted within ten (10) business days of system installation at a mutually agreeable time, and the utility shall be given the opportunity to witness the tests. If the utility opts not to witness the test, the applicant will send the utility within five (5) days of the test a written notification, certifying that the system has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 5. The applicant must have complied with and must continue to comply with all contractual and technical requirements.

STEP 6: Final Acceptance

Within five (5) business days of receiving the written test notification from Step 5, the utility will either issue to the applicant a formal letter of acceptance for interconnection, or will request that the applicant and utility set a date and time for an on-site verification and witness operation of the system. This joint on-site verification must be completed within ten (10) business days after being requested. Within five (5) business days of the completion of the on-site verification, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the system.

3.2.3 Application Forms

New York State Standardized Application for Single Phase Interconnection of Parallel Generation Equipment 25kW or Smaller. (Reference ATTACHMENT 3)

Application Process Steps for Systems Above 25kW up to 2MW

Exception: For inverter based systems above 25 kW up to 200 kW, applicants may follow the expedited application process outlined under Section I. B. of the SIR, as long as the inverter-based system has been certified and tested in accordance with UL 1741

(November 2005 revision) and the utility has approved the project accordingly. The utility has fifteen (15) business days from original application submittal to determine and notify the applicant in writing of its findings. If the utility determines that the inverter-based system is not eligible for the fast track or expedited application process, the applicant can:

1) Proceed with the remaining steps of Section I.C of the SIR (Systems above 25 kW up to 2 MW); or

2) Request a review by the Department of Public Service.

For non-inverter based systems and those inverter based systems not certified and tested in accordance with UL 1741 above 25 kW up to 200 kW, the potential applicants and utilities are encouraged to use expedited application process (Section I. B.), but only in circumstances where the utility deems it to be appropriate.

STEP 1: Initial Communication from the Potential Applicant.

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project.

Technical staff from the utility discusses the scope of the interconnection with the potential applicant (either by phone or in person) to determine what specific information and documents (such as an application, contract, technical requirements, specifications, listing of qualified type-tested equipment/systems, application fee information, applicable rate schedules, and metering requirements) will be provided to the potential applicant. The preliminary technical feasibility of the project at the proposed location may also be discussed at this time. All such information and a copy of the standardized interconnection requirements must be sent to the applicant within three (3) business days following the initial communication from the potential applicant, unless the potential applicant indicates otherwise. A utility representative will be designated to serve as the single point of contact for the applicant (unless the utility informs the applicant otherwise) in coordinating the potential applicant's project with the utility.

STEP 3: Potential Applicant Files an Application.

The potential applicant submits an application to the utility. The submittal must include the completed standard application form, including a copy of equipment certification to UL 1741 (November 2005 revision) as applicable, a three line diagram specific to the proposed system, a letter of authorization (if applicant is agent for the customer), and payment of a non-refundable $350 application fee, except that the fee shall be refunded to net metering customer-generators unless applied toward the cost of installing a dedicated transformer. If the applicant proceeds with the project to completion, the application fee will be applied as a payment to the utility's total cost for interconnection, including the cost of processing the application. Within five (5) business days of receiving the application, the utility will notify the applicant of receipt and whether the application has been completed adequately. It is in the best interest of the applicant to provide the utility with all pertinent technical information as early as possible in the process. If the required documentation is presented in this step, it will allow the utility to perform the required reviews and allow the process to proceed as expeditiously as possible.

STEP 4: Utility Conducts a Preliminary Review and Develops a Cost Estimate for the Coordinated Electric System Interconnection Review (CESIR).

The utility conducts a preliminary review of the proposed system interconnection. Upon completion of the preliminary review, the utility will inform the applicant as to whether the proposed interconnection is viable or not, and provide the applicant with an estimate of costs associated with the completion of the CESIR. The preliminary review shall be completed and a written response detailing the outcome of the preliminary review shall be sent to the applicant within fifteen (15) business days of the completion of Step 3. The utility's response to applicants proposing to interconnect aggregate DG systems above 25 kW and up to 2 MW, or proposing to interconnect to network systems will include preliminary comments on requirements for protective relaying, metering and telemetry**.**

STEP 5: Applicant Commits to the Completion of the CESIR

Prior to commencement of the CESIR, the applicant shall provide the following information to the utility:

- a complete detailed interconnection design package
- the name and phone number of the individual(s) responsible for addressing technical and contractual questions regarding the proposed system, and
- if applicable, advanced payment of the costs associated with the completion of the CESIR

The complete detailed interconnection design package shall include:

(1) Electrical schematic drawing(s) reflecting the complete proposed system design which are easily interpreted and of a quality necessary for a full interconnection. The drawings shall show all electrical components proposed for the installation, and their connections to the existing on-site electrical system from that point to the PCC.

(2) A complete listing of all interconnection devices proposed for use at the PCC. A set of specifications

for this equipment shall be provided by the applicant upon request from the utility.

(3) The written verification test procedure provided by the equipment manufacturer, if such procedure is required by this document.

(4) Three (3) copies of the following information:

- Proposed three line diagram of the generation system showing the interconnection of major electrical components within the system. Proposed equipment ratings clearly needs to indicate:

1) Number, individual ratings, and type of units comprising the above rating;

2) General high voltage bus configuration and relay functions;

3) Proposed generator step-up transformer MVA ratings, impedances, tap settings and winding voltage ratings;

- Electrical studies as requested by the utility to demonstrate that the design is within acceptable limits, inclusive and limited to the following: system fault, relay coordination, flicker, voltage drop, and harmonics.

STEP 6: **Utility Completes the CESIR**

The CESIR will consist of two parts:

(1) a review of the impacts to the utility system associated with the interconnection of the proposed system, and

(2) a review of the proposed system's compliance with the applicable criteria set forth below.

A CESIR will be performed by the utility to determine if the proposed generation on the circuit results in any relay coordination, fault current, and/or voltage regulation problems. A full CESIR may not be needed if the aggregate generation is less than: 50 kW on a single-phase branch of a radial distribution circuit; or 150 kW on a single distribution feeder.

The CESIR shall be completed within sixty (60) business days of receipt of the information set forth in Step 5. For systems utilizing type-tested equipment, the time required to complete the CESIR may be reduced.

Upon completion of the CESIR, the utility will provide the following, in writing, to the applicant:

(1) utility system impacts, if any;

(2) notification of whether the proposed system meets the applicable criteria considered in the CESIR process;

(3) if applicable, a description of where the proposed system is not in compliance with these requirements;

(4) Subject to subsections (a) through (d) below, a good faith, detailed estimate of the total cost of completion of the interconnection of the proposed system and/or a statement of cost responsibility for a dedicated transformer(s) or other required interconnection equipment:

(a) with respect to an applicant that is <u>not</u> to be net-metered, an estimate shall be provided and shall include the costs associated with any required modifications to the utility system, administration, metering, and on-site verification testing;

(b) with respect to an applicant that <u>is</u> to be net-metered and that is either a Farm Wind or Non-Residential Wind applicant intending to install wind electric generating equipment with a rated capacity of more than 25 kW, an estimate shall be provided and (i) shall include the costs associated with any required modifications to the utility system, administration, metering, and on-site verification testing, and such applicant shall be informed that it is responsible for one-half of such costs, and (ii) shall include the applicant's responsibility for the actual cost of installing any dedicated transformer(s) and other safety equipment up to the maximum set forth in subsection (d) below;

(c) with respect to an applicant that <u>is</u> to be net-metered (but not a Farm Wind or Non-Residential Wind applicant covered in subsection (b) above) such applicant shall have no responsibility for the interconnection costs described in subsection (b)(i) above, and a statement shall be provided showing the applicant's responsibility for the actual cost of installing any dedicated transformer(s) and other safety equipment up to the maximum set forth in subsection (d) below and;

(d) with respect to an applicant that is to be net-metered, if the utility determines that it is necessary to install a dedicated transformer(s) or other equipment to protect the safety and adequacy of electric service provided to other customers, the applicant shall be informed of its responsibility for the actual costs for installing the dedicated transformer(s) and other safety equipment. The following table reflects the maximum responsibility each designated applicant shall have with respect to the actual cost of the dedicated transformer(s) and other safety equipment.

Maximum Expense for Dedicated Transformer and Other Safety Equipment for Net Metered Customers (Above 25kW up to 2MW)

Generator Type	Generator Size	Maximum Equipment Responsibility
Solar	Over 25 kW up to 2 MW	As determined by Utility*
Wind	Over 25 kW up to 2 MW	As determined by Utility*
Farm Wind	Over 25 kW up to 500 kW	$5,000
Farm Waste	Up to 1 MW	$5,000

***Subject to review by the Commission at the request of the Customer**

STEP 7: Applicant Commits to Utility Construction of Utility's System Modifications.

The applicant and utility will execute a standardized contract for interconnection and the applicant will provide the utility with an advance payment for the utility's estimated costs as identified in Step 6 (estimated costs will be reconciled with actual costs in Step 11).

STEP 8: Project Construction.

The applicant will build the facility in accordance with the utility-accepted design. The utility will commence construction/installation of system modifications and metering requirements as identified in Step 6. Utility system modifications will vary in construction time depending on the extent of work and equipment required. The schedule for this work is to be discussed and agreed upon with the applicant in Step 6.

STEP 9: The Applicant's Facility is Tested in Accordance With the Standardized Interconnection Requirements.

The verification testing will be performed in accordance with the written test procedure provided in Step 5 and any site-specific requirements identified by the utility in Step 6. The final testing will be conducted within ten (10) business days of complete installation at a mutually agreeable time, and the utility shall be given the opportunity to witness the tests. If the utility opts not to witness the test, the applicant will send the utility within five (5) days of the test a written notification, certifying that the system has been installed and tested in compliance with the SIR, the utility-accepted design, and the equipment manufacturer's instructions.

STEP 10: Interconnection.

The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 9. In addition, the applicant must have complied with and must continue to comply with the contractual and technical requirements.

STEP 11: Final Acceptance and Utility Cost Reconciliation.

If the utility witnessed the verification testing, then, within ten (10) business days of the test, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the system. If the utility did not witness the verification testing, then, within ten (10) business days of receiving the written test notification from Step 9, the utility will either issue to the applicant a formal letter of acceptance for interconnection, or will request that the applicant and utility set a date and time for an on-site verification and witness operation of the system. This joint on-site verification must be completed within twenty (20) business days after being requested. Within ten (10) business days of the completion of the on-site verification, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the system. At this time, the utility will also reconcile its actual costs related to the applicant's project against the application fee and advance payments made by the applicant. The applicant will receive either a bill for any balance due or a reimbursement for overpayment as determined by the utility's reconciliation, except that a net metering applicant may not be charged in excess of the cost of installing the dedicated transformer(s) or other safety equipment described above in Step 6. The applicant may contest the reconciliation with the utility. If the applicant is not satisfied, a formal complaint may be filed with the Commission.

3.2.4 Application Forms

New York State Standardized Application for Single Phase Interconnection of Parallel Generation Equipment above 25kW up to 2MW. (Reference ATTACHMENT 4)

3.3 Independent Power Producer Generation Rated Greater Than 2 MW and Less Than or Equal to 20 MW that does not fall under the Small Generation Interconnection Procedure of the NYISO,

3.3.1. Introduction

The section provides the framework for processing applications for the interconnection of IPP generation, rated greater than 2 MW but less than or equal to 20 MW, to the Utility system.

3.3.2. Engineering Review Process

Upon receipt of a request from a Developer for interconnection requirements associated with the installation and operation of a generating facility in parallel with the Utility's system, the Developer will be sent a copy of this Bulletin and a copy of the applicable Utility standard agreement. If the Developer wishes to proceed with a project, it shall furnish the Utility with ALL of the information asterisked (*) in ATTACHMENT1, and described in Section 4. Within ten (10) business days of receipt of the initial application and design package, the Utility shall review the information for completeness and, if necessary, provide the Developer, in writing, with a list of missing information and a cost estimate to complete the Preliminary Technical Review.

PRELIMINARY TECHNICAL REVIEW PROCESS

Upon receipt of a complete application and design package and advanced payment, if applicable, the Utility shall commence the Preliminary Technical Review, which shall be completed in four (4) months following receipt of a complete application and design package, and advanced payment, if applicable, unless otherwise agreed upon by the Parties. The duration of the Preliminary Technical Review is dependent upon the size, location and interconnect scheme of the proposed generating facility. The Preliminary Technical Review shall consist of a review of the Developer's proposed system capacity, impact of the proposed generation on the Utility system, system characteristics and general system regulation to determine if the interconnection is viable.

Once the Preliminary Technical Review is completed, the Utility will provide the Developer, in writing, the results of the review. Such results shall include (i) any problems or deficiencies in the proposed design or information provided, (ii) identification of required system modifications, and (iii) a preliminary cost estimate for the required system modifications and completion of the Technical Review. **The Developer will be responsible for all costs pursuant to Section 5 of this Bulletin.**

Following receipt of the Preliminary Technical Review results, if the Developer elects to proceed with the project, it must provide to the Utility a proposed project schedule noting dates for obtaining major permits for the project, purchasing and receiving major equipment, starting and completing construction of the Developer's facilities, synchronizing with the Utility system and commencing Commercial Operation. This project schedule may be subject to modifications since it must also reflect the schedule for any modifications/additions to the Utility's system.

FINAL TECHNICAL REVIEW PROCESS

In order for the Utility to begin the Final Technical Review, the Developer must submit to the Utility all of the information listed in ATTACHMENT 1 and described in Section 4, and provide advanced payment for the cost of the review. The Final Technical Review will be completed in no more than six (6) months following receipt of ALL information required and advanced payment, unless otherwise agreed upon by the Parties. The duration of the review is dependent upon on the size, location and interconnection scheme of the proposed generating facility. If any portion of the submitted design or data is not acceptable, the Utility will comment on those areas and notify the Developer to make the appropriate revisions. The Developer must submit the revisions to the Utility before the Final Technical Review will continue. Any delay in the Developer's response to the Utility's comments will directly delay completion of the Final Technical Review and Final Acceptance of the proposed generation and protection design.

Upon completion of the Final Technical Review, the Utility will provide the Developer, in writing, the results of the review. If the review determines the Utility's acceptance of the Developer's proposed generation and protection design (in accordance with this Bulletin), then the written notification will include a Formal Acceptance. Formal Acceptance of the Developer's proposed generation and protection design is the first stage in the process leading to the Utility's acceptance of the Developer's generating facility for interconnection to the Utility system (see Section 8).

3.4 Generating Facility, or Merchant Transmission Facility Interconnecting to the New York State Transmission System under the Large Generation Interconnection Procedures or the Small Generation Interconnection Procedures.

If the proposed generating facility or merchant transmission facility is interconnecting to the New York State Transmission System, then the Developer must follow the procedures set forth in Attachment X, or Attachment Z to the NYISO OATT.

4 INFORMATION REQUIREMENTS

In order for the Utility to review and formally accept the Developer's proposed interconnection and protection design, the Developer shall furnish the Utility will ALL of the information listed in ATTACHMENT 1. This Section 4 provides a brief description of the items listed in ATTACHMENT 1 to assist the Developer in preparing the application and design package. Items with an asterisk (*) are required for the Preliminary Technical Review or Protection System Impact Study.

*4.1 Utility Form NB 232**

To permit the Utility to begin the Engineering Review Process for the Developer's proposed generation project, the Developer must complete the Independent Power Producer Generator Notice (Form NB-232)(See ATTACHMENT 2)

If, at any time during the Engineering Process, modifications are made to the Developer's design that affect the original information furnished on Form NB-232, then the Developer shall provide a revised Form NB-232 to the Utility.

Form NB-232 contains information that is supplied by both the Utility and the Developer. A description of the information to be furnished by the Developer is provided below.

4.1.1 Developer Information

a)	Developer Name:	Name of Developer proposing the IPP project.
b)	Developer Address:	Developer's address.
c)	Telephone No. Primary:	Developer's primary telephone number.
d)	Telephone No. Alternate:	Developer's alternate telephone number.
e)	Proposed Generating Facility Location:	Location of the proposed generating facility, including street, city/town/village, county, state and zip code.

4.1.2 Generator Information

a)	Manufacturer:	Generator manufacturer's name and model number.
b)	Type:	Type of generator (i.e., induction, synchronous, dc with synchronous inverter, ac with synchronous inverter, etc.)
c)	Rated Output (kVA):	Maximum rated output of the generating unit in kVA. For multiple generating units, the Developer shall note the quantity and rating of the units. The Developer shall complete the Generator Information

		Sheet (ATTACHMENT 5) for the Utility's Preliminary Technical Review Process.
d)	Nameplate Voltage:	Rated output voltage of the generating unit(s).
e)	Power Factor:	Power factor of the generating unit(s).
f)	Phase:	Indication of whether the generating unit is single or three phase.
g)	Disconnect Device:	Indication of the manufacturer, type and continuous and interrupting ratings of the disconnecting device proposed to isolate the generating facility from the Utility system.
h)	Prime Mover:	Source of power to the generating unit (i.e., wind, hydro, wood, solar, natural gas, etc.).

4.1.3 Merchant Transmission Interconnection Information

a)	Capacity/Impedances	<u>All relevant information regarding the lines capacity to transmit power and impedances so that the new line can be modeled in the ASPEN 1 Liner.</u>

4.1.4 End User Facility Interconnection Information

a)	Load Size and Profile	<u>All relevant information regarding the real and reactive side of the new load and the profile over time so that the new load can be modeled in the ASPEN 1 Liner.</u>

4.1.5 General Information

a)	Consultant:	Name and telephone number of Developer's consulting engineer, if any.
b)	Electrical Contractor:	Name and telephone number of Developer's electrical contractor, if any. If Developer is providing its own personnel for electrical work, it must indicate so.
c)	Equipment Supplier:	Name and telephone number of the manufacturer or firm supplying generation equipment for the project.
d)	Interconnection Date:	Estimated date that the Developer's generating facility will be ready for interconnection to the Utility system.

4.1.6 Remarks

This section shall be used to provide any additional information necessary to complement the information provided above. Any unusual conditions or potential problems should be noted. If the Prime Mover is something other than wind or solar, the Developer should provide the turbine or engine size.

4.2 Application Form*

This form is the standard application form found in the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less and Connected in Parallel with Utility Distributions Systems, and included in ATTACHMENTS 3&4.

4.3 Project Schedule

A schedule (bar chart, CPM, etc.), noting dates for obtaining major permits and financing for the project, purchasing and receiving major equipment, starting and completing construction of the Developer's facilities, synchronizing with the Utility system, and commencing Commercial Operation.

4.4 Site Plan*

A detailed site plan showing the Developer's facilities, including any interconnection facilities (substations, etc.), in relation to the Utility's existing facilities. This site plan must be of sufficient detail to accurately locate the Developer's facilities on a U.S. Geological Survey ("USGS") topographic map.

4.5 Description of Operation*

A brief description of the intended operation and control of the Developer's facilities, including the method of starting and the number of starts per day. Any unusual switching procedures or unique operating condition that may be planned shall also be explained.

4.6 One Line Electrical Diagram of Complete Facility*

The one line diagram must accurately represent the Developer's electrical equipment up to the point of interconnection with the Utility system. The one line diagram must include, at a minimum, the following: Disconnect Switch(es), step-up transformer(s), circuit breaker(s) and contactors, switches, generator(s), current and voltage transformers, capacitors, surge arresters, and station service transformer.

4.7 One Line Relay Diagram*

The one-line relay diagram must accurately represent the Developer's electrical equipment up to the point of interconnection with the Utility system. The one-line diagram shall include, as a minimum, the following:

- Disconnect Switch(es), including voltage class and continuous current rating
- step-up transformer(s), including size, voltage ratings, winding connections and impedance
- circuit breaker(s) and contactors, including voltage rating and symmetrical current interrupting rating
- any generator(s), including size, rated voltage and winding connection
- current transformers (CTs), including ratio of full winding, tap used and accuracy class of full CT
- voltage transformers (VTs), including ratio and winding connection
- station service transformer(s), including ratio and winding connection
- proposed protective relay device function numbers

*4.8 Three Line Relay or AC Elementary Diagram(s)**

This diagram must detail the interconnection wiring for the equipment detailed on the one-line diagrams. In particular, this diagram must illustrate how the protective relays and instrument transformers are connected. (This may not be necessary if the instrument transformer winding connections are shown on the One Line Relay Diagram).

4.9 Elementary Control or DC Elementary Control Diagram(s)

Sometimes referred to as a schematic diagram, the elementary control diagram depicts the electrical arrangement of the relays and contacts associated with the protective relay scheme, the generator control scheme and the circuit breaker trip and close schemes.

*4.10 Generator, Exciter and Governor Information Sheets**

The Developer shall complete the Generator (ATTACHMENT 5), Exciter (ATTACHMENT 6), and Governor (ATTACHMENT 7) Information sheets. Incomplete information sheets will result in delays since the Developer will be requested to provide the missing information.

4.11 Equipment Nameplate Data and Electrical Ratings

The Developer shall provide the following information, as a minimum for each piece of equipment:

a. Prime Mover - type, manufacturer, power rating, rated speed.

b. Interface/Step-up Transformer(s)* (from proposed generation to point of common coupling) - manufacturer, rated kVA, high and low voltage ratings, winding connections, winding impedance, neutral impedance.

c. Interrupting Devices* - manufacturer, type, rated voltage, rated current, interrupting capacity, operating time.

d. Current Transformers (CTs)* - manufacturer, type, accuracy class, ratio of all devices utilized for protection, control and data telemetering (if required).
e. Voltage Transformers (VTs)* - manufacturer, type, primary and secondary voltage, winding connections, VA rating of all devices utilized for protection, control and data telemetering (if required).
f. Line/Disconnect Switch(es)* - manufacturer, type, rated voltage and current, rated interrupting capacity and location of switch.
g. Capacitor Bank - manufacturer, rated kVAR and connection.
h. Battery and Charger or Source of Power Supply to Protective Relays and Interrupting Devices (such as a UPS) - manufacturer, rating, dc voltage range and output capacity and duration upon loss of ac supply.
i. Surge Arresters - manufacturer, catalog number, MCOV rating.
j. Other – additional information will be requested by the Utility, as required, to complete the review of the Developer's design.

4.12 Proposed Relay Types and Settings for Fault Isolation Protection Schemes

The Developer shall provide a list of relays proposed for the purpose of providing isolation protection, detection of short circuits and other system abnormalities on the Utility system, and detection of short circuits within the generating facilities to disconnect the generating facilities from the Utility system. Each relay's function, manufacturer, model, and range shall be indicated. The proposed settings for the relays provided for detection of short circuits and other system abnormalities on the Utility system shall be provided. For microprocessor relays, the proposed logic to be programmed in the relays and input/output assignments shall be provided. The settings for the isolation protection relays are specified in Sections 6.1.1.1.1 and 6.1.1.1.2 or Section 6.2.2.1.6 of this Bulletin, depending on the size and type of the proposed generator.

4.13 Telemetering Information (when applicable)

When data telemetering is required, the Developer shall provide the Utility with the following telemetering information:

a. AC Elementary Diagram(s) - showing current, potential and external power inputs to the transducers, test switches, etc.
b. Connection diagram(s)
c. Types and ratings of integrated electronic devices ("IEDs"), IED connection(s) and associated scaling.
d. Copies of certificates of test for the metering current and voltage transformers. When certificates are not available, a typical curve for the type of transducer shall be furnished.

4.14 Protective Relay Communications and Monitoring Systems Information (when applicable)

When protective relay communications and/or monitoring equipment are required, the Developer shall provide the Utility with the following information (refer to Section 6.3):

a. Equipment vendor bid proposals, correspondence, equipment drawings, certified test reports and instruction books for the protective relay communications and/or monitoring equipment.

b. Copy of the Communications Service Request Form, Ground Potential Rise calculations and earth resistance measurement data for leased telephone channels for protective relaying.

Although it's the Developer's responsibility to order the communication circuits and provide the necessary info for facilities owned by the Developer, the Utility can use their phone company account representatives to advise on how best to facilitate the order (Telco procedures preclude Energy East from taking an active role in the actual ordering of circuits owned by others).

4.15 Method of Excitation

The means for providing the generator excitation (rotating dc generator, static var source, etc.) must be described.

4.16 Minimum Site Load Without Generation On Line*

The Developer's minimum site load (kVA, power factor), is required to determine the overall load/generation ratio, to determine the impact of the Developer's generation on the Utility system and to ensure that an adequate design is employed.

4.17 Generation Saturation Curve

Per unit armature voltage versus field current for open and short circuit conditions that identify and specify the saturation factor values at 1.0 and 1.2 per unit armature voltage values.

4.18 Exciter Saturation Curves

Per unit exciter field voltage versus exciter field current during load and no-load conditions that identify and specify the exciter field current values at 75% and 100% of maximum exciter field voltage values.

4.19 Block Diagrams

System block diagram, complete with corresponding constants for each type of governor and exciter proposed.

4.20 Regulatory Filings, Impact Statements, License Applications and Other Permit Applications

The Developer shall notify the Utility (provide copies) of all regulatory filings, impact statements, license applications and all other permit applications required by federal, state and local agencies for the Developer's generating facilities. When the Utility's interconnection facilities are included in the Developer's regulatory filings, impact statements, license applications and other permit applications for the generating facilities, the Developer shall provide this information to the Utility for review and acceptance, prior to filing with the agency. Copies of all regulatory approvals and permits obtained by the Developer shall be provided to the Utility upon the Utility’s request, including all conditions applied to the approvals.

4.21 Additional Information

The Utility shall request from the Developer, and the Developer shall provide, any additional information required that the Utility deems necessary for completion of the technical reviews.

5 UTILITY SYSTEM MODIFICATIONS

5.1 General

This Section 5 provides information associated with Utility system modifications. If the proposed project is subject to the NYISO OATT, to the extent that this Section 5 conflicts with Attachment X and/or Attachment S, Attachment X and Attachment S shall apply.

5.2 Preliminary Cost Estimate

If Utility system modifications are required, the Utility will provide the Developer with a preliminary cost estimate and estimated completion date for the system modifications at the completion of the Utility's review process as described in the applicable sections of Section 3. A firm schedule for the completion of the Utility's system modifications will be provided after the design has been finalized and Utility internal authorization has been obtained.

5.3 Final Cost Estimate

Upon completing the final design and obtaining Utility internal authorization for any Utility system modifications required due to the Developer's proposed generation, the Utility will provide the Developer with a final engineering quality estimate for the required Utility system modifications. **The Developer will be responsible for all Utility actual incurred costs associated with the required Utility system modifications.** The Utility will provide an advance payment schedule to the Developer, which will be the basis for invoices to be issued monthly by the Utility, to cover the estimated cost of all Utility system modifications. Invoices will be issued to the Developer so that payments are received from the Developer prior to completion of the work. Any differences between the estimated and actual incurred Utility costs will be resolved at the completion of the required system modifications through reimbursements to the Developer (for overpayments), or an invoice issued to the Developer (for additional incurred costs).

5.4 Engineering, Design and Construction

Unless otherwise negotiated with the Developer, the Utility will engineer, design, procure equipment for and construct any modifications required on the Utility system due to the installation of the Developer's facility. If Agreements state that interconnection facilities (electric transmission, distribution, and/or substation facilities) are to be provided by the Developer and transferred to the Utility upon completion and acceptance by the Utility, the Developer shall engineer, design, procure equipment for, construct and test all facilities in accordance with the Utility's latest design guidelines and equipment and construction specifications. The Utility will provide these documents to the Developer as required.

The Developer shall submit to the Utility for review and acceptance all design drawings, engineering documentation and equipment specifications for all interconnection facilities to be transferred to the Utility upon completion and acceptance by the Utility. The Utility will require at least thirty (30) days to review all submitted documentation and either accept or provide comments to the Developer. Depending on what interconnection facilities are required, the Utility will furnish a list of design packages and documentation to be submitted by the Developer for the Utility's review and acceptance.

5.5 Regulatory Approvals and Permits

The Developer shall obtain all regulatory approvals and permits required for all interconnection facilities to be constructed by the Developer and transferred to the Utility. The Developer shall provide copies of all regulatory filings, impact statements, license applications and all other permit applications involving interconnection facilities to be transferred to the Utility. The Developer shall provide this information to the Utility for review and acceptance, prior to filing with the agency. Copies of all regulatory approvals and permits obtained by the Developer shall be provided to the Utility, including all conditions applied to the approvals.

5.6 Installation and Testing

During the installation and testing of the interconnection facilities to be transferred to the Utility, the Utility will have the right to be present to verify that the facilities are in complete accordance with the Utility's design guidelines and equipment and construction specifications and standards. The Developer will be required to correct all work not completed in accordance with the Utility's standards. Upon the Utility's acceptance of the interconnection facilities and energization of the Developer's generating facility, the Developer shall transfer ownership of the interconnection facilities to the Utility.

5.7 Affected Systems

Where other public utilities are involved in the Developer's project, the Developer shall coordinate all project activities. The Developer shall be responsible for negotiating and/or obtaining any additional agreements or contract requirements with the other public utilities.

6 ELECTRICAL INTERCONNECTION REQUIREMENTS

This Section 6 specifies the Utility's technical interconnection requirements for Independent Power Producer generation connected in parallel with the Utility's system. Generation that does not operate in parallel with the Utility's system is not subject to these requirements. The requirements in this section have been developed based on typical Utility industry design, operating procedures, and safety practices in order to ensure the safety of Utility personnel and equipment, Utility customers, and the general public.

The Developer's proposed generation interconnection shall have 60 Hz alternating current characteristics compatible with the Utility system at the point of interconnection.

6.1 New York State Standardized Interconnection Requirements for New Distributed Generation 2 MW or Less Connected in Parallel with Utility Distribution Systems

6.1.1 Design Requirements

6.1.1.1 Common

The owner shall provide appropriate protection and control equipment, including a protective device that utilizes an automatic disconnect device that will disconnect the generation in the event that the portion of the utility system that serves the generator is de-energized for any reason or for a fault in the generator-owner's system. The generator-owner's protection and control equipment shall be capable of automatically disconnecting the generation upon detection of an islanding condition and upon detection of a utility system fault.

The generator-owner's protection and control scheme shall be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified by the required operating ranges. Upon request from the utility, the generator-owner shall provide documentation detailing compliance with the requirements set forth in this document.

The specific design of the protection, control and grounding schemes will depend on the size and characteristics of the generator-owner's generation, as well the generator-owner's load level, in addition to the characteristics of the particular portion of the utility's system where the generator-owner is interconnecting.

The generator-owner shall have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface shall disconnect for voltage or frequency trip conditions sensed by the protective devices. Voltage protection shall be wired phase to ground for single phase installations and for applications using wye grounded-wye grounded service transformers.

The settings below are listed for single-phase and three-phase applications using wye grounded-wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review will be conducted by the utility and the revised settings identified in Step 6 of the Application Process.

The requirements set forth in this document are intended to be consistent with those contained in IEEE Std 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. The requirements in IEEE Std 1547 above and beyond those contained in this document shall be followed[1].

6.1.1.1.1 Voltage Response

The required operating range for the generators shall be from 88% to 110% of nominal voltage magnitude. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator-owner’s equipment ceases to energize the PCC and includes detection and intentional time delay.

6.1.1.1.2 Frequency Response

The required operating range for the generators shall be from 59.3 Hz to 60.5 Hz. For generators greater than 30 kW the utility may request that the generator operate at frequency ranges below 59.3 Hz as defined in IEEE Std 1547. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator-owner’s equipment ceases to energize the PCC and includes detection and intentional time delay.

If the generation facility is disconnected as a result of the operation of a protective device, the generator-owner’s equipment shall remain disconnected until the utility’s service voltage and frequency have recovered to acceptable voltage and frequency limits for a minimum of five (5) minutes. Systems greater than 25 kW that do not utilize inverter based interface equipment shall not have automatic recloser capability unless otherwise approved by the utility. If the utility determines that a facility must receive

[1] It is expected that IEEE Std 1547 will eventually supersede the need for explicit technical standards in New York State. However, until such time as all IEEE 1547 series of standards are complete and approved, this standard will take precedence.

permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

6.1.1.2 Synchronous Generators

Synchronous generation shall require synchronizing facilities. These shall include automatic synchronizing equipment or manual synchronizing with relay supervision, voltage regulator, and power factor control.

For all synchronous generators sufficient reactive power capability shall be provided by the generator-owner to withstand normal voltage changes on the utility's system. The generator voltage VAR schedule, voltage regulator, and transformer ratio settings shall be jointly determined by the utility and the generator-owner to ensure proper coordination of voltages and regulator action. Generator-owners shall have synchronous generator reactive power capability to withstand voltage changes up to 5% of the base voltage levels.
A voltage regulator must be provided and be capable of maintaining the generator voltage under steady state conditions within plus or minus 1.5% of any set point and within an operating range of plus or minus 5% of the rated voltage of the generator.

Generator-owners shall adopt one of the following grounding methods for synchronous generators:

a) Solid grounding

b) High- or low-resistance grounding

c) High- or low-reactance grounding

d) Ground fault neutralizer grounding

Synchronous generators shall not be permitted to connect to utility secondary network systems without the approval of the utility.

6.1.1.3 Induction Generators

Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the PCC is acceptable based on current inrush limits. The same requirements also apply to induction generation connected at or near synchronous speed because a voltage dip is present due to an inrush of magnetizing current. The generator-owner shall submit the expected number of starts per specific time period and maximum starting kVA draw data to the utility to verify that the voltage dip due to starting is within the visible flicker limits as defined by IEEE Std 519, Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.

Starting or rapid load fluctuations on induction generators can adversely impact the utility's system voltage. Corrective step-switched capacitors or other techniques may be necessary. These measures can, in turn, cause ferroresonance. If these measures (additional capacitors) are installed on the customer's side of the PCC, the utility will review these measures and may require the customer to install additional equipment.

6.1.1.4 Inverters

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design shall be such as to disconnect this synchronous inverter upon a utility system interruption.

It is recommended that equipment be selected from the "Certified Equipment" list maintained by the PSC. Interconnected Distributed Generating systems utilizing equipment not listed in the "Certified Equipment" list must meet all functional requirements of IEEE Std 1547 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section.

Synchronization or re-synchronization of an inverter to the utility system shall not result in a voltage deviation that exceeds the requirements contained in Section II.E, Power Quality. Only inverters designed to operate in parallel with the utility system shall be utilized for that purpose.

A line inverter can be used to isolate the customer from the utility system provided it can be demonstrated that the inverter isolates the customer from the utility system safely and reliably.

6.1.1.5 Minimum Protective Function Requirements

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the distributed generation facility
- Voltage level of the interconnection
- Location of the distributed generation facility on the circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the distributed generation facility under isolated conditions
- Amount of existing distributed generation on the local distribution system.

AS A RESULT, PROTECTION REQUIREMENTS CAN NOT BE STANDARDIZED ACCORDING TO ANY SINGLE CRITERIA.

MINIMUM PROTECTIVE FUNCTION REQUIREMENTS SHALL BE AS DETAILED IN THE TABLE BELOW. ANSI C37.2, ELECTRIC POWER SYSTEM DEVICE FUNCTION NUMBERS, ARE LISTED WITH EACH FUNCTION.

SYNCHRONOUS GENERATORS	INDUCTION GENERATORS	INVERTERS
OVER/UNDER VOLTAGE (FUNCTION 27/59)	OVER/UNDER VOLTAGE (FUNCTION 27/59)	OVER/UNDER VOLTAGE (FUNCTION 27/59)
OVER/UNDER FREQUENCY (FUNCTION 81O/81U)	OVER/UNDER FREQUENCY (FUNCTION 81O/81U)	OVER/UNDER FREQUENCY (FUNCTION 81O/81U)
		ANTI-ISLANDING PROTECTION

The need for additional protective functions shall be determined by the utility on a case-by-case basis. If the utility determines a need for additional functions, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, and an explicit justification for the necessity of the enhanced capability. The utility shall specify and provide settings for those functions that the utility designates as being required to satisfy protection practices. Any protective equipment or setting specified by the utility shall not be changed or modified at any time by the generator-owner without written consent from the utility.

The generator-owner shall be responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment. Protective devices shall utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the generator-owner’s protective devices, including loss of control power, shall open the automatic disconnect device, thus disconnecting the generation from the utility system. A generator-owner’s protection equipment shall utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points.

All interface protection and control equipment shall operate as specified independent of the Calendar date.

6.1.1.6 Metering

The need for additional revenue metering or modifications to existing metering will be reviewed on a case-by-case basis and shall be consistent with metering requirements adopted by the Commission.

Any incremental metering costs are included in interconnection costs that may be required of an applicant. (As described in Section C, Step 6, net metered Solar, Farm Waste, Farm Wind (25 kW or Less) and Residential-Wind customer-generators are only required to contribute to the cost of dedicated transformer(s) and other safety equipment, and Farm Wind and Non-Residential Wind customer-generators with systems of 25 kW and larger are only responsible for payment of one-half of interconnection costs other than dedicated transformer(s) and other safety equipment).

The following Table summarizes the New York Net Metering Rules

New York (PSL 66-j) - Net Metering[2]

Incentive Type:	Net Metering Rules			
Eligible Renewable/Other Technologies:	Solar		Biogas	Micro CHP / Fuel Cell
Applicable Sectors:	Residential	Non-Residential	Farm-Waste	Residential
Limit on System Size:	25 kW	Up to 2MW	1 MW	10 kW
Limit on Overall Enrollment:	1% of 2005 Demand per IOU for Solar, Biogas, Micro CHP, and Fuel Cells Combined			

New York (PSL 66-l) - Net Metering[2]

Incentive Type:	Net Metering Rules		
Eligible Renewable/Other Technologies:	Wind		
Applicable Sectors:	Residential	Non-Residential	Farm-Service Wind
Limit on System Size:	25 kW	Up to 2MW	500 kW
Limit on Overall Enrollment:	.3% of 2005 Demand per IOU		

[2] Refer to specific utility tariff leaves for more detailed rules and regulations applicable to net metering.

6.1.2 Operating Requirements

The generator-owner shall provide a 24-hour telephone contact. This contact will be used by the utility to arrange access for repairs, inspection or emergencies. The utility will make such arrangements (except for emergencies) during normal business hours.

Voltage and frequency trip set point adjustments shall be accessible to service personnel only.
Any changes to these settings must be reviewed and approved by the utility.

The generator-owner shall not supply power to the utility during any outages of the utility system that serves the PCC. The generator-owner's generation may be operated during such outages only with an open tie to the utility. Islanding will not be permitted. The generator-owner shall not energize a de-energized utility circuit for any reason.

The disconnect switch specified for system size larger than 25kW and non-inverter based systems of 25 kW or less in Section II.D, Disconnect Switch, may be opened by the utility at any time for any of the following reasons:

a. to eliminate conditions that constitute a potential hazard to utility personnel or the general public;

b. pre-emergency or emergency conditions on the utility system;

c. a hazardous condition is revealed by a utility inspection;

d. protective device tampering;

e. parallel operation prior to utility approval to interconnect.

The disconnect switch may be opened by the utility for the following reasons, after notice to the responsible party has been delivered and a reasonable time to correct (consistent with the conditions) has elapsed:

a. A generator-owner has failed to make available records of verification tests and maintenance of its protective devices;

b. A generator-owner's system adversely impacts the operation of utility equipment or equipment belonging to other utility customers;

c. A generator-owner's system is found to adversely affect the quality of service to adjoining customers.

The utility will provide a name and telephone number so that the generator-owner can obtain information about the utility lock-out.

The generator-owner shall be allowed to disconnect from the utility without prior notice in order to self generate.

Under certain conditions a utility may require direct transfer trip (DTT). The utility shall provide detailed evidence as to the need for DTT.

If a generator-owner proposes any modification to the system that has an impact on the interface at the PCC after it has been installed and a contract between the utility and the generator-owner has already been executed, then any such modifications must be reviewed and approved by the utility before the modifications are made.

6.1.3 Dedicated Transformer

The utility reserves the right to require a power-producing facility to connect to the utility system through a dedicated transformer. The transformer shall either be provided by the connecting utility at the generator-owner's expense, purchased from the utility, or conform to the connecting utility's specifications. The transformer may be necessary to ensure conformance with utility safe work practices, to enhance service restoration operations or to prevent detrimental effects to other utility customers. The transformer that is part of the normal electrical service connection of a generator-owner's facility may meet this requirement if there are no other customers supplied from it. A dedicated transformer is not required if the installation is designed and coordinated with the utility to protect the utility system and its customers adequately from potential detrimental net effects caused by the operation of the generator.

If the utility determines a need for a dedicated transformer, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, the conditions under which the dedicated transformer is expected to enhance safety or prevent detrimental effects, and the expected response of a normal, shared transformer installation to such conditions.

6.1.4 Circuit Breakers and Other Interrupting Devices

Facilities requiring Circuit Breakers or other types of fault current interrupting devices shall be specified by a NYS Professional Engineer and have sufficient capacity to interrupt the fault currents that are expected given the system conditions based on the point of interconnection. NYSEG and RG&E do not specify a breaker duty. Each application is evaluated based on the system conditions where the breaker is to be placed in service. The interconnection customer designs the interconnection and NYSEG and RG&E review and then accepts the design if then engineering is correct.

6.1.5 Insulators

Facilities requiring insulators of any type shall be specified by a NYS Professional Engineer and have sufficient capability to operate effectively given the system conditions based on the point of interconnection and coordinated with the utility system. NYSEG does not specify insulation requirements. Each application is evaluated based on the system conditions where the equipment is to be placed in service. The interconnection customer designs the interconnection and NYSEG reviews and then accepts the design if then engineering is correct. Here are some typical BI Levels used on the NYSEG system, the capabilities of the insulators chosen for a developers facility must be proposed by the developers engineer and accepted by the Utility.

Nominal Voltage	Effectively Grounded BIL	Non Effectively Grounded BIL
345kV		NA
230kV		NA
115kV		NA
46 kV		
34.5kV Transmission		
34.5kV Distribution Group Op Load Break Switch (600 amp) Pad Switchgear (600 amp) High Voltage Fusing Transformer	200 150 150 150	200 150 150 150
15kV and below Group Op Load Break Switch (600 amp) Pad Switchgear (600 amp) High Voltage Fusing Transformer	 110 95 125 95	 110 95 125 95

6.1.6 Disconnect Switch

Facilities with system size larger than 25 kW and non-inverter based systems of 25 kW or less shall be capable of being isolated from the utility system by means of an external, manual, visible, gang-operated, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the customer-generator, and located between the generating equipment and its interconnection point with the utility system.

The disconnect switch must be rated for the voltage and current requirements of the installation.

The basic insulation level (BIL) of the disconnect switch shall be such that it will coordinate with that of the utility's equipment. Disconnect devices shall meet applicable UL, ANSI, and IEEE standards, and shall be installed to meet all applicable local, state, and federal codes. (New York City Building Code may require additional certification.)

The disconnect switch shall be clearly marked, "Generator Disconnect Switch," with permanent 3/8 inch or larger letters or larger.

The disconnect switch shall be located within 10 feet of the utility's external electric service meter. If such location is not possible, the customer-generator will propose, and the utility will approve, an alternate location. The location and nature of the disconnect switch shall be indicated in the immediate proximity of the electric service entrance. The disconnect switch shall be readily accessible for operation and locking by utility personnel in accordance with Section II.B, Operating Requirements. The disconnect switch must be lockable in the open position with a 3/8" shank utility padlock.

6.1.7 Power Quality

The maximum harmonic limits for electrical equipment shall be in accordance with IEEE 519 to limit the maximum individual frequency voltage harmonic to 3% of the fundamental frequency and the voltage Total Harmonic Distortion (THD) to 5% on the utility side of the PCC. In addition, any voltage fluctuation resulting from the connection of the customer's energy producing equipment to the utility system must not exceed the limits defined by the maximum permissible voltage fluctuations border line of visibility curve identified in IEEE Std 519. This requirement is necessary to minimize the adverse voltage effect upon other customers on the utility system.

6.1.8 Power Factor

If the average power factor, as measured at the PCC, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator will be negotiated with the utility as a commercial item.

Induction power generators may be provided VAR capacity from the utility system at the generator-owner's expense. The installation of VAR correction equipment by the generator-owner on the generator-owner's side of the PCC must be reviewed and approved by the utility prior to installation.

6.1.9 Islanding

Generation interconnection systems must be designed and operated so that islanding is not sustained on utility distribution circuits. The requirements listed in this document are designed and intended to prevent islanding.

6.1.10 Equipment Certification

In order for the equipment to be acceptable for interconnection to the utility system without additional protective devices, the interface equipment must be equipped with the minimum protective function requirements listed in the table in Section II.A.5 and be tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in compliance with Underwriter's Laboratories (UL) 1741, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources (November 7, 2005 revision).

For each interconnection application, documentation including the proposed equipment certification, stating compliance with UL 1741 by an NRTL, shall be provided by the applicant to the utility. Supporting information from an NRTL website or UL's website stating compliance is acceptable for documentation.

If an equipment manufacturer, vendor, or any other party desires, documentation indicating compliance as stated above may be submitted to the Department of Public Service Commission for listing under the "Certified Equipment" list on the Department's website (http://www.dps.state.ny.us/distgen.htm).

Certification information for equipment tested and certified to UL 1741 (November 2005 revision) by a non-NRTL shall be provided by the manufacturer, or vendor to the contacts listed on the Public Service Commission's website (http://www.dps.state.ny.us/distgen.htm) for review before final approval and posting under the Public Service Commission's "Certified Equipment" list. Utilities are not responsible for reviewing and approving equipment tested and certified by a non-NRTL.

If an equipment is UL 1741 (November 2005 revision) certified by an NRTL and compliance documentation is submitted to the utility, the utility shall accept such equipment for interconnection in New York state. All equipment certified to UL 1741 (November 2005 revision) by an NRTL shall be deemed 'certified equipment' even if it does not appear on the Department of Public Service Commission's website.

Utility grade relays need not be certified per the requirements of this section.

6.1.11 Verification Testing

All interface equipment must include a verification test procedure as part of the documentation presented to the utility. Except for the case of small single-phase inverters as discussed later, the verification test must establish that the protection settings meet the SIR requirements. The verification testing may be site-specific and is conducted periodically to assure continued acceptable performance.

Upon initial parallel operation of a generating system, or any time interface hardware or software is changed, the verification test must be performed. If a protective relay must be physically disconnected from a circuit in order for it to be tested, a verification test must be performed. A qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory-trained and certified technicians, and licensed electricians with experience in testing protective equipment. The utility reserves the right to witness verification testing or require written certification that the testing was successfully performed.

Verification testing shall be performed at least once every four years. All verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The generator-owner shall maintain verification test reports for inspection by the utility.

Single-phase inverters and inverter systems rated 25 kW and below shall be verified upon initial parallel operation and once every four years as follows: the generator-owner shall interrupt the utility source and verify that the equipment automatically disconnects and does not reconnect for at least five minutes after the utility source is reconnected. The owner shall maintain a log of these operations for inspection by the connecting utility. Any system that depends upon a battery for trip power shall be checked and logged at least annually for proper voltage. Once every four (4) years the battery must be either replaced or a discharge test performed.

6.2 Electrical Interconnection Requirements for Independent Power Producer Generation Rated Greater than 2 MW, Merchant Transmission Lines and End User Facilities.

6.2.1 General

This Section 6.2 specifies the Utility's interconnection technical requirements for Developers of generating sources rated greater than 2 MW and operating in parallel with the Utility system, Merchant Transmission Lines, and End User Facilities connecting to the Utility Transmission Grid.

The protection requirements described in this Section 6.2 are those necessary to protect the Utility system from the Developer's facility and to minimize any adverse consequences to the Utility system. Illustrated in ATTACHMENTS 8, 9, 10 and 11 are typical protection, control and grounding schemes that could be employed by the Developer to meet those requirements. It should be noted, however, that the specific design of the protection, control and grounding schemes will depend on the size and characteristics of the Developer's facility as well as the characteristics of the particular portion of the Utility system to which the Developer is connecting the facility. The Developer's relay calculations and settings associated with the interconnection protection must be submitted to the Utility for review and acceptance, and should be done early enough in the project such that any changes identified during the Utility review do not adversely affect schedules.

Facilities connected to the Utility transmission and subtransmission system shall be capable of coordinating their underfrequency protective relaying with the NPCC Underfrequency Load Shedding Curve (see ATTACHMENT 14). The Developer's facilities shall be capable of remaining connected (not trip or be damaged) through major system disturbances until both stages of the Utility underfrequency load shedding scheme have had a chance to operate and reduce system load. The Developer shall take whatever steps are necessary during the design of their facility to ensure that they can withstand sustained underfrequency operation. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 30% of area load to assist in arresting frequency decay and to minimize the possibility of a widespread system collapse. In conformance with the Emergency Operating Criteria, the facility shall be required to remain connected to the system during the frequency decline to allow the objectives of the NPCC automatic load shedding program to be achieved.

For facilities proposed for interconnection to circuits that are equipped with underfrequency load shedding relays, these relays will be required to be relocated from the circuit of origin to another circuit on the Utility system at the developer’s expense.

The Developer's system design must conform to all applicable National Electrical Code ("NEC"), National Electrical Safety Code ("NESC"), American National Standards Institute ("ANSI") and Institute of Electrical and Electronic Engineers ("IEEE") standards and applicable government regulations.

It is not the Utility's intention to ensure that the Developer's generator or facilities other than the interconnection are adequately protected. If a safety concern is identified during the course of reviewing the Developer's design or witnessing start-up testing, the Utility will bring it to the Developer's and/or their agent's attention for corrective action. Ultimately, the responsibility to identify compliance with applicable safety codes and government regulations and to resolve any opposing views regarding safety code interpretation lies with the authorized inspection organization.

The Utility may require the Developer to provide two independent, redundant relaying systems in accordance with NPCC criteria for the protection of the bulk power system if the interconnection is to the bulk power system, or if it is determined that delayed clearing of faults within the generating facility adversely affects the bulk power system.

6.2.2 System Design Requirements for Independent Power Producer Generation Rated Greater than 2 MW, Merchant Transmission Lines and End User Facilities.

6.2.2.1 Protection & Control

The protection requirements described in this document are those necessary to protect the Utility system from the Developer's facility and minimize its impact on the system. Other devices necessary solely for the protection of the Developer's equipment and to ensure its safe operation shall be the Developer's responsibility. It is not the Utility's intent to assess such protection in the Utility Engineering Review Process.

6.2.2.1.1 *PE Engineer*

The Developer is required to obtain the services of a qualified, New York State licensed Professional Engineer ("P.E.") to design the protection system to meet the Utility's requirements, as well as the Developer's own requirements. The responsible P.E.'s seal shall be affixed on all of the Developer's design documentation that is required to be submitted to the Utility for review and acceptance.

6.2.2.1.2 *Consultant(s)*

To help minimize the potential for delays in the Utility Engineering Review Process, it is highly recommended that the Developer's consultant(s) have extensive background in power system protection and relay calibration and testing. It is the sole responsibility of the Developer to ensure the qualification of the Developer's consultant(s).

6.2.2.1.3 *Protection Schemes*

The Utility requires that Developers with a generating source(s) operating in parallel with the Utility system design, purchase, and install protection schemes at their location that are designed to detect the following:

- System abnormalities and disturbances on the Utility system to which the Developer's generation is interconnected (Utility fault protection scheme).
- Faults within the Developer's plant, to separate the plant from the Utility system, avoiding outages to other Utility customers supplied on the same circuit to which the generation is interconnected (plant fault protection scheme).

- Backfeeding, by the Developer's generation, to the Utility system when the Utility supply is separated from the Utility system to which the Developer's generation is interconnected (isolation protection scheme).

6.2.2.1.4 ***Line Protection for Interconnections to Utility Subtransmission or Transmission Circuits***

For facilities proposed for interconnection to Utility subtransmission or transmission circuits, the infeed that is introduced into the circuit from the proposed facility has an adverse impact on the Utility protective relays at the line terminals. The infeed causes the Utility protective relays to be less sensitive for short circuits that occur on the protected line beyond the proposed interconnection point. In addition, settings for the Utility line terminal protective relays may not be able to be calculated to protect the line for all operating conditions (e.g. all generators on line, no generators on line, etc.).

Because of this impact on the Utility line protection schemes, a developer shall not be allowed to interconnect to a Utility subtransmission or transmission line as a third line terminal. The developer will be required to install facilities at the proposed point of interconnection to split the line into two separate lines. The Developer shall install line protection equipment at each new line terminal that can interface with the protective relays at each of the Utility line terminals.

6.2.2.1.5 ***Protective Relays***

The protective relays used by the Developer to meet the Utility's fault and isolation protection requirements must be Utility-approved Utility Grade Relays (see Section 2 - Definitions). The following suppliers are currently approved by the Utility for the fault and isolation protection relays shown in Figures 1, 2, and 3 (ATTACHMENTS 8, 9, and 10):

- ABB (former Westinghouse, ASEA, and BBC types only)
- Basler (BE1 class relays only)
- Beckwith
- General Electric and GE/Multilin
- Schweitzer Engineering Laboratories (SEL)
- Siemens

6.2.2.1.6 ***Fault Protection Schemes***

The Developer's fault protection scheme must isolate the Developer's facility from the Utility system for, but not necessarily limited to, the following abnormalities and disturbances:

- Faults within the Developer's equipment;
- Multiphase and ground faults on the Utility system between the Developer's facility and a Utility-designated "system location"; and

- Single phasing of a three-phase facility (open conductor).
- Loss of power supply to the protective relays within the plant
- Protective relay failure (relay trouble alarm)
- Loss of Control Power

6.2.2.1.7 *Isolation Protection Scheme*

The Developer's isolation protection scheme must automatically isolate the Developer's facility from the Utility system for loss of the Utility supply. The Developer's facility must not supply other Utility customers in the event of a loss of the Utility source. The isolation protective equipment would typically be designed to sense a "step change" in the facilities output voltage, current, or frequency upon loss of the Utility source. NOTE: The "step change" resulting from the loss of the Utility supply may or may not be locally detectable at the Developer's location. If not, additional remote communications protection may be required.

Figures 1, 2 and 3 (ATTACHMENTS 8, 9, and 10) illustrate examples of the minimum protection requirements available to the Developer for various typical systems. The specific design of the protection schemes will depend on the facility type and kVA size, the Developer's own site load, the type of Utility supply feeder and its associated loads, as well as the method of grounding selected. The circuit breaker used to disconnect the facility from the Utility system shall be tripped either directly from the protective relay or through one interposing relay.

The windings of the VTs for the undervoltage and overvoltage elements shall be connected so that the secondary voltage in which they monitor accurately emulates the voltages of the Utility circuit to which the facility is interconnected. For example, if the VTs are installed on the secondary of a delta-wye power transformer, they must be connected wye-delta to properly emulate the phase-to-neutral voltages of the Utility circuit.

For isolation protection relays, the Utility requires the following minimum settings:

Underfrequency (81U)

Coordinate with the NPCC Underfrequency Load Shedding Curve shown in ATTACHMENT 14 (i.e., the setting must be on or below the curve shown).

Overfrequency (81O)

Pick-up at no more than 60.5 Hz and operate in no greater than 0.5 seconds.

Undervoltage (27)

Pick-up at no less than 90% of nominal supply voltage and operate in no greater than 1.0 seconds.

Overvoltage (59)

For facilities interconnected to Utility circuits that are ungrounded, or not effectively grounded, pick-up at no more than 110% of nominal supply voltage and operate instantaneously.

For facilities interconnected to Utility circuits that are effectively grounded, pick-up at no more than 110% of nominal supply voltage and operate in no greater than 1.0 seconds.

6.2.2.1.8 *Fault Protection Relays*

For fault protection relays, it is the Developer's responsibility to perform the necessary calculations and determine the proper settings. The Utility will provide the Developer with pertinent Utility system data and the appropriate fault protection criteria. Once the Developer has completed the calculations and finalized these settings, the calculations and settings must be provided to the Utility for review and acceptance. For microprocessor relays, this includes all associated logic and input/output programming.

6.2.2.1.9 *Current Transformers (CTs) Used for Fault Protection Relays*

Relay accuracy CTs (CTs whose accuracy class begin with a “C” or a “T” followed by a voltage class (e.g. C400, T200, etc.) must be used for all protective relays installed within the plant that are used for fault protection. Metering accuracy CTs can saturate when exposed to fault currents, and are thus unacceptable.

6.2.2.1.10 *Voltage Transformers (VTs) Used for Fault and Isolation Protection*

Winding connections for VTs used to provide voltage quantities to fault and isolation protection relays shall be reviewed on a case-by-case basis. This will be done to assure that the phase voltages of the interconnecting utility system are correctly emulated to the relays so that they will operate properly for the appropriate conditions. The VT winding connection depends on the configuration of the utility system, the GSU transformer connection and other factors. VTs used for fault and isolation protection shall not be connected open delta-open delta, because the phase voltages of the interconnecting utility system cannot be correctly emulated to the fault and isolation protection relays regardless of the winding connection of the GSU power transformer to the utility.

6.2.2.1.11 *High Speed Protection vs. Time-Delayed Protection*

The developer may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection system on Utility lines.

6.2.2.1.12 *Local Breaker Failure Protection*

The Developer may be required to provide local breaker failure protection, which may include Direct Transfer Tripping to the Utility line terminal(s), in order to detect and clear faults within the generating source that cannot be detected by Utility backup protection or that could result in undesirable interruption to utility customers.

6.2.2.1.13 *Relay Test Switches*

Relay test switches (ABB FT-19R or equivalent) shall be installed for each microprocessor-based relay that provides isolation protection and/or detection of short circuits or other abnormalities on the Utility system. At least one test switch is required for each relay. This requirement is primarily to assure that any relay output is not rewired incorrectly following the required initial and periodic relay testing. Installation of relay test switches also aids to facilitate and expedite relay testing.

6.2.2.2 Grounding

The Utility transmission, subtransmission and distribution facilities are all designed and built to maintain a specific level or type of grounding. The interconnection of the Developer's facility to Utility facilities may adversely affect that grounding. In order to maintain the existing level or type of grounding on the circuit, the interconnecting facility must comply with the following criteria:

Developer's interconnecting to wye-grounded distribution circuits must provide a ground source to maintain effective grounding on the circuit. The ground source must ensure that under all conditions where the Developer's facility becomes isolated with the Utility's distribution load, the distribution circuit remains effectively grounded. (A ground source provides effective grounding if, during a phase-to-ground fault, the voltages on the unfaulted phases with respect to ground do not exceed 1.35 per unit.)

a. During a phase-to-ground fault on the Utility's distribution circuit, the Developer's facility may be isolated with the phase-to-ground fault if the Utility source opens before the Developer's protection detects the fault condition and isolates the facility from the Utility system. If the Developer's facility does not provide effective grounding during the period that the facility is isolated with the phase-to-ground fault, the system neutral can shift, creating an overvoltage on the two remaining unfaulted phases. All phase-to-ground connected loads isolated with the facility will be subjected to this overvoltage, which can reach 173% of nominal voltage. This high voltage could quickly damage Utility equipment and/or other customer's equipment.

b. The qualified New York State licensed P.E. responsible for the design of the Developer's system shall be aware that the ground source at the Developer's location will provide a path for a portion of the zero-sequence fault current for <u>all</u> phase-to-ground faults on the circuit. Should this additional fault current path adversely affect the operation of existing Utility ground relaying and/or fusing on the circuit, additional zero-sequence impedance may have to be added to the Developer's ground source (while still maintaining effective grounding), or the ground source may have to be tripped-off simultaneously when the facility is tripped for faults.

c. The following are examples of methods that the Developer may use to provide the required ground source at his location. Figures 4.1, 4.2 and 4.3 (ATTACHMENT 11) illustrate each of these methods, respectively:
- A wye-grounded/wye-grounded step-up transformer with a wye-grounded generator.
- A grounding transformer at the point of interconnection. A wye-grounded/delta or zig-zag transformer may be used.
- A wye-grounded/delta step-up transformer.

The Developer's interconnecting to delta-connected distribution circuits typically will not be required, nor allowed, to provide a ground source for the Utility system. However, the Developer must provide the appropriate protective relaying at the Point of Interconnection to detect ground fault on the Utility electrical system and disconnect the facility from the Utility system.

The Developer's interconnecting to transmission or subtransmission facilities, either delta- or wye-connected, will be reviewed individually to determine if there is a need for the Developer to provide a ground source for the Utility system.

6.2.2.3 Synchronizing and Reclosing

Installations with synchronous generators or self-commutated inverters are required to use Utility Grade synchronizing equipment to parallel their generation with the energized Utility system. In general, installations with induction generators or line-commutated inverters are not required to have synchronizing equipment.

The connection of any type of facility to a de-energized portion of the Utility system is prohibited.

When the Developer's fault interrupting device is tripped via fault or isolation protective relay equipment, reclosing of that device must be delayed until the Utility system has been restored for a minimum of five (5) minutes.

NOTE: The facility should be aware that Utility autoreclosing may cause transient shaft torque on the Developer's machine(s) and transient line overvoltages if it (they) is (are) still connected to the Utility system when reclosing occurs.

For fault initiated operations on transmission, subtransmission and distribution circuits, the Utility substation and line fault interrupting devices (excluding fuses) typically reclose automatically without hot-line supervision or synchronizing. Dead time on the Utility circuit before the first reclosing occurs typically ranges from 2 to 15 seconds. As noted previously, if the Developer's facility remains on-line when reclosing occurs, the Developer's equipment may be damaged by a possible out-of-sync reclose. The Utility may require the installation of hot-line supervision or synchronizing to existing fault interrupting devices on transmission, subtransmission, and distribution circuits when developer owned facilities are connected to them. The utility reserves the right to add hot-line supervision to block automatic reclosing at the Developers expense so that other customers are not impacted by a voltage transient caused by an out of step close.
A Developer may be asked to provide an initial synchronizing plan.

6.2.2.4 Disconnect Switch

6.2.2.4.1 *General*

Developer’s facilities shall be capable of being isolated from the Utility system by means of an external, manual, visible, gang-operated, load break Disconnect Switch. The Disconnect Switch shall be installed, owned and maintained by the owner of the facility, and located between the developer’s equipment and its interconnection point with the Utility system.

a. The Disconnect Switch shall be clearly marked, "Disconnect Switch," with permanent 3/8 inch letters or larger.
b. The Disconnect Switch shall be located within 10 feet of the Utilities' external electric service meter or the location and nature of the dispersed r Disconnect Switches shall be indicated in the immediate proximity of the electric service entrance.
c. The Disconnect Switch shall be readily accessible for operation and locking by Utility personnel at all times. Operation of this switch by the Utility is at the discretion of the Utility without prior notice to the power producer.
d. The Disconnect Switch must be lockable in the open position with a standard Utility padlock.

6.2.2.4.2 *Standards and Ratings*

The Disconnect Switch must be rated for the voltage and current requirements of the installation. The basic insulation level (BIL) of the Disconnect Switch shall be such that it will coordinate with that of the Utility’s equipment. Disconnect devices shall meet applicable UL, ANSI and IEEE standards, and shall be installed to meet all applicable local, state and federal codes.

6.2.2.4.3 *Utility Access*

The Disconnect Switch may be opened by the Utility for any of the following reasons:

a. To eliminate conditions that constitute a potential hazard to Utility personnel or the general public.
b. Pre-emergency or emergency conditions on the Utility system.
c. A hazardous condition is revealed by a Utility inspection.
d. Protective device tampering

The Disconnect Switch may be opened by the Utility for the following reasons, after notice to the power producer has been delivered and a reasonable time to correct (consistent with the conditions) has elapsed:

a. Power producer has failed to properly maintain the protective devices.
b. Power producer's system interferes with Utility equipment or equipment belonging to other Utility customers.
c. Power producer's system is found to affect quality of service of adjoining customers.
d. Failure to make Verification Test records available to the Utility upon request.

6.2.2.4.4 *Notification of Disconnection*

The customer shall be allowed to disconnect from the Utility without prior notice in order to self-generate.

6.2.2.5 Power Factor Correction

If the Developer installs an induction machine or uses an inverter, power factor correction equipment may be required. If the Utility determines in its sole judgment that the use of power factor correction equipment is necessary for VAR support, the Developer shall:

- Install such power factor correction equipment on its systems, as specified and accepted by the Utility; and/or
- Be responsible for all Utility-incurred costs associated with the addition of such power factor correction equipment installed by the Utility on the Utility system.

6.2.2.6 Harmonics

The following is the Utility's policy, based on the most current IEEE standards, regarding harmonic distortion limits that apply to all customers, including IPPs:

> “Harmonic distortion due to a Developer's facility shall be limited such that the harmonic voltage distortion as measured at any point on the Utility system will

> not exceed 3% for any single frequency or 5% total harmonic distortion ("THD"), or otherwise be determined by the Utility to cause problems with the Utility or other customers. THD is defined as the square root of the sum of the squares of the harmonic voltages divided by the magnitude of the fundamental (60 hertz) voltage."

If the percent THD is above the limit, the Developer may need to install a filter to meet the requirement.

If a harmonic-related problem with other Utility customers can be traced to a Developer's facility, the Developer must cease operation of the facility and remedy the problem.

6.2.2.7 Flicker

The Developer's facility shall not create unacceptable voltage fluctuation or flicker conditions on the Utility system, as determined by the Utility. Refer to GRAPH 1 (ATTACHMENT 13) for flicker limitations, based on the most current IEEE standards. The Developer shall limit voltage fluctuations in accordance with the 3% curve for transmission or Subtransmission system interconnections, or the 4% curve for distribution system interconnections.

6.2.2.8 Ferroresonance

6.2.2.8.1 *Description*

Studies have shown that ferroresonant overvoltages can occur on Utility T&D systems. These are produced by the discharging and charging of the system capacitance through the highly non-linear magnetizing reactance of the system transformers as they pass into and out of a saturated condition. The result is high overvoltage and distorted waveforms, which not only contain the ferroresonance but also all the natural resonant frequencies of the distribution circuits excited by the ferroresonant pulses.

6.2.2.8.2 *Conditions*

Four conditions must be present for ferroresonant overvoltages to occur:

- The facility must be separated from the Utility source (Islanding condition).
- The kilowatt load in the Island must be less than three times the facility's rating.
- The system capacitance must be greater than 25% of the facility's rating.
- There must be at least one transformer connected to the island.

6.2.2.8.3 *Impact On Customer Equipment*

Ferroresonant overvoltages can result in customer equipment and wiring being subjected to up to three times rated voltage. This can result in damage to both customer-owned appliances and equipment as well as Utility-owned equipment, and may even result in a fire.

6.2.2.8.4 *Equipment Requirements*

If, during the Preliminary Technical Review, it is determined that a ferroresonant overvoltage condition is possible, the Utility protection engineer will investigate if it is feasible to remove capacitor banks from the branch or circuit to which the facility will be connected. If this is determined not to be feasible, then unidirectional Direct Transfer Trip (DTT) equipment will be required to be installed at the Utility substation or line recloser and the generation facility. Through this equipment, the Utility's relays or recloser, upon detection of a short circuit on the feeder or branch, will key a DTT signal to the generation facility via telephone channel to Disconnect the generation from the faulted circuit prior to opening of the Utility breaker or recloser.

6.2.3 Metering

The metering scheme(s) required to measure the power delivered to the Utility, or any service power required by the Developer and supplied by the Utility (i.e., temporary, back-up, maintenance, or permanent service), will be dictated by the Agreement terms negotiated between the Utility and the Developer. The metering scheme(s) will be designed by the Utility.

6.2.3.1.1 *Metering Point at Point of Interconnection*

When the metering point is located at the point of interconnection, the Developer shall provide space and mounting structures for the metering equipment in the Developer's interconnection facilities. A suitable Disconnect Switch(es) (group-operated, with a visible open) operable and lockable by the Utility, shall be provided by the Developer to isolate the metering instrument transformers (VTs and CTs), for maintenance and testing. The metering CTs shall be located on the Utility side of the metering VTs. The Developer shall also provide the conduit(s) required between the instrument transformer secondary junction box(es) and the metering enclosure(s) and for any telephone and SCADA RTU‘s connections.

a. The Utility will normally purchase, install, test and maintain the metering instrument transformers (VTs and CTs), meters, enclosure(s), and ancillary equipment required for metering of the Developer's facility. The Utility will provide instrument transformer outline drawings and meter enclosure physical information to the Developer to incorporate into the design of the Developer's interconnection facilities. The Developer shall coordinate the location of the metering equipment with the Utility. The Developer shall provide drawings showing the location and mounting structure details for the metering instrument transformers and meter enclosure, for the Utility's review and acceptance.

b. The Utility will install all connections between the instrument transformer secondaries and the meter test switches, along with meter interconnections and connections to ancillary equipment.

c. When required, the Developer shall supply additional source(s) of 120 volt ac, single phase station power to the meter ancillary equipment. The supply circuit(s) shall be dedicated for the Utility's use only. The Utility will make all connections to the ancillary equipment from a specified demarcation point. The Utility will provide the Developer with power requirements. This supply circuit shall not be interrupted during routine switching and maintenance outages.

d. In some instances, to facilitate construction and installation, the Utility may authorize the Developer to include the purchase and/or installation of meters, metering instrument transformers and meter test switch(es) in the Developer's interconnection facilities. The Utility will provide equipment specifications and accuracy requirements for meters and instrument transformers to be purchased by the Developer. The Developer shall provide equipment drawings and certified test data for the Utility's review and acceptance The requirements detailed in the next section (i.e. 6.2.1.8.6) are applicable in this instance.

e. The Developer shall furnish a dedicated standard "voice-grade POTS" (plain old telephone system) telephone channel and jack to a designated demarcation point for remote meter interrogation (usually at the meter). Also, any wiring between revenue meters and SCADA RTU’s is the developer’s responsibility. Connections between meters and RTU’s are normally made through a fiber optic transceiver unit.

f. The Utility shall have access to all metering equipment located within the Developer's interconnection facilities to perform initial and routine in-service maintenance and testing. The Utility will notify the Developer prior to entering the Developer's facilities.

6.2.3.1.2 ***Meter Point at Location Other than the Interconnection Point***

Where interconnect requirements dictate the building of a substation that the Utility will own, operate and maintain, the Developer is required to purchase and install the revenue meter(s), associated revenue grade metering CTs and VTs and meter test switch(es). The metering point is to be located where the change of ownership occurs. The typical ownership line of demarcation is noted on the POI Guide Relay One Line Diagram (CR-8031) as a dashed line. It is important that any additional metering requirements beyond the POI for back-up and/or supplemental service or for black start capabilities be defined at the outset. Generally, metering equipment for conventional services not involving the POI, will be supplied by the Utility.

For metering at the POI, the Utility will specify the exact meter type(s) and model(s). The developer will purchase and install the meter(s), CT's/VT's, and complete the wiring between CT/VT secondary windings and meter test switches and between the meter test switches and meter case(s). Revenue meters must be powered from a reliable 120 VAC auxiliary source. This source must be uninterruptable.

Revenue meters typically supply MW, MWh, MVAR, Volts, Amps, and Frequency signals to an on site Supervisory Control and Data Acquisition (SCADA) Remote Terminal Unit (RTU) through an RS-485 connection using DNP 3.0 protocol. The developer is required to complete all connections between meters and SCADA RTU's and also between meters and the station telephone demarcation point. Revenue meters require a dedicated 2-wire, half duplex POTS line or dedicated port off a telephone switch. Connections between meters and RTU's are normally made through a fiber optic transceiver unit. The Utility will test and commission the revenue metering equipment.

New York State requires all devices used in revenue metering applications to be PSC approved. The following web site contains a list of approved devices~~.~~:

http://www.dps.state.ny.us/approved_meter_list.PDF

During the early design phase of the project, the developer is required to provide the Utility with maximum generator output in units of kVA or MVA and on site minimum load without generation. At this point, the developer should make note of any future plans to expand the facility that will result in increased generation capacity. Because of the range between maximum output and minimum on site load when the facility is not generating, the Utility may require the use of high accuracy (0.15%), extended range CTs. Using expected maximum and minimum load information supplied by the developer, the Utility will size the CT's and, at the developer's request, provide final review of all revenue grade metering devices before any PO's are issued.

For revenue metering applications, only wound type VTs are acceptable; capacitive type voltage transformers cannot be used. Metering VT/CT secondary windings must be dedicated and used for the sole purpose of supplying current and metering potential to the measuring elements of revenue meters. No other devices such as relays, panel meters, transducers, potential sensing devices, etc. are to be connected off the secondary windings of metering VTs and CTs. VTs with dual secondary windings are acceptable under the condition that one of the secondary windings is reserved and dedicated for revenue metering purposes and the connected burden on the remaining windings is kept to a minimum. The minimum conductor size for all secondary connections must be #10 AWG solid or stranded copper wire. Single point grounding of VT/CT secondary windings is required. The location of this ground must be at the meter test switch. Secondary fusing of metering VTs is not permitted.

The Utility requires certified factory test data for all revenue metering CTs and VTs. This test data must be specific to each device (i.e. representative or typical test data is not acceptable). The developer is required to provide the Utility with the following information on all metering CTs and VTs:

REVENUE GRADE VOLTAGE TRANSFORMERS (VT's):

	Phase A	Phase B	Phase C
Acquisition Date:			
Manufacturer:			
Model:			
Serial Number:			
Dual Winding Flag (Y/N):			
Dual Ratio Flag (Y/N):			
In Service Ratio Vpr : Vsec			
Rated % Accuracy (ANSI Class):			
Burden Rating:			
Thermal Rating (VA):			
BIL Rating:			
RCF @ Rated Bdn:			
PACF @ Rated Bdn.:			
RCF @ Zero VA			
PACF @ Zero VA:			

REVENUE GRADE CURRENT TRANSFORMERS (CT's):

	Phase A	Phase B	Phase C
Acquisition Date:			
Manufacturer:			
Model:			
Serial Number:			
Voltage Class:			
Dual Ratio Flag (Y/N):			
In Service Ratio (XXXX:5):			
Rated % Accuracy (ANSI Class):			
Burden Rating:			
BIL Rating:			
TRF:			
RCF @ FL:			
PACF @ FL:			
RCF @ LL:			
PACF @ LL:			

The above information, including factory certified test reports must be sent to the Utility for review and acceptance.

Note that instrument transformers are long lead time items and should be ordered as early as possible. The instrument transformers can be shipped directly to the construction site. Revenue meters on the other hand must be shipped directly from the manufacturer to the Utility Meter Labs so they can be programmed and tested before installation.

Depending on the size of the generation and the existing circuit load, the Utility may require installation of hourly interval metering at the Utility source substation or other upstream device, at the Developer’s expense, so the Utility can accurately track circuit loading against generation output.

6.2.3.1.3 ***Dedicated Phone Line***

The Developer will be responsible for providing 2-wire, dial-up, dedicated telephone line(s) at the demarcation point adjacent to the Utility’s metering location(s). The telephone line(s) shall provide the Utility with remote metering reading capability. The Developer shall be responsible for all costs related to obtaining, installing, testing, commissioning and maintaining the telephone line(s) as those costs may be charged by the telephone company.

6.2.3.1.4 ***Instrument Transformers***

Instrument transformers utilized for metering the Developer's generation delivered to the Utility, or any service power required by the Developer and supplied by the Utility will not be used for other functions (i.e., protective relaying, telemetering, etc.).

6.2.3.1.5 ***Cost Responsibility***

The Developer will be responsible for all costs associated with the installation, testing and maintenance of the metering equipment. The Utility will retain ownership of all metering equipment.

6.2.4 Data Telemetering

For Developer's generating facilities with an installed capacity of greater than 2 MW, or for Merchant Generators, plant net Kilowatt, Kilovar, Kilowatt-hour output, and bus voltage shall be required to be continuously (every two seconds) sent to the Utility's Energy Control Center. At the Utility's option, circuit breaker status, control and critical alarms may also be required. For Developer's generating facilities 2 MW or less, data telemetering may be required at the Utility's option, depending on the interconnection system requirements.

6.2.4.1.1 *Data Transmittal*

This data may be transmitted, at the Utility's option, to a local Utility facility that has a Remote Terminal Unit ("RTU") on the Utility's Supervisory Control and Data Acquisition ("SCADA") system for retransmission to the Utility's Energy Control Center. Alternatively, a Utility SCADA RTU may be installed directly at the Developer's facility.

6.2.4.1.2 *Dedicated Leased Phone Channel*

If the Utility requires the Developer to install an RTU at their facility, the Developer must provide RTU communications to the Utility's Energy Control Center via a dedicated leased telephone channel. The Developer shall obtain a leased telephone channel to a Utility connection point (located at an AT&T POP facility for all inter-LATA circuits). For intra-LATA circuits, the Developer shall connect to the Utility's Energy Control Center via a dedicated channel. The Developer will be invoiced by the Utility for the connection between the AT&T POP facility and the Utility's Energy Control Center. The Developer shall be responsible for ordering and paying for the telephone channel from the Developer's generating facilities to the dedicated connection point.

6.2.4.1.3 *Telemetry Information Requirements*

A 485 communications interface will be connected to the billing meter to carry the analog measurements, via DNP3.0 protocol, to the RTU communications port. Any IED's for the analog measurement of volts, watts, and reactive volt-amperes shall conform to ANSI standards C39.1, C39.5, and C37.90A. Instrument transformers shall conform to ANSI standard C57.13.

The Utility will inform the Developer of full scale values for volts, watts and vars. This information will determine the calibration range of the transducer and define scaling resistor requirements.

The Developer shall provide pertinent telemetering information, as noted in Section 4.13, for the Utility's review and acceptance.

The Developer will be required to bring the analog value communications from the billing meter, the digital alarms and the breaker position, and the breaker control wiring to a demarcation block for the RTU. The Developer will also prepare a point list diagram that describes the order of the signals brought to the terminal block. The Utility technicians will deliver the RTU, mount it next to the terminal block, wire from the terminal block into the RTU, and program the RTU.

6.2.4.1.4 *Equipment and Cost Responsibility*

The Developer shall be responsible for all telemetering equipment and be required to pay for all the costs associated with its purchase, installation, operation, test and maintenance of this equipment.

6.2.4.1.5 ***Testing***

After initial testing and acceptance, the Developer is required to provide the Utility with certified transducer test results once every two years to coincide with the required protection system periodic test schedule.

6.3 Protective Relay Communications and Monitoring Systems for Independent Power Producer Generation Rated Greater than 2 MW, Merchant Transmission Lines and End User Facilities.

This Section 6.3 specifies the Utility's requirements for the purchase and installation of protective relay communications systems and monitoring equipment. Communication facilities for protective relaying applications (i.e., pilot and/or direct transfer trip), and/or monitoring equipment which are required (as defined in the system modifications) for the Utility's and the Developer's facilities for the purpose of accepting IPP Generation, Merchant Transmission Facilities, and End-User Facilities for interconnection, shall be designed, purchased, and installed in accordance with the following requirements:

6.3.1 Terminal Equipment

6.3.1.1.1 ***Ownership***

The metering point will generally establish the demarcation. All equipment on the Developer's side of the metering point will be owned, operated, and maintained by the Developer. All equipment on the Utility side of the metering point will be owned, operated, and maintained by the Utility. At the Utility's option, the Developer may purchase equipment to be installed on the Utility side of the metering point. However, upon Utility acceptance of the equipment for interconnection and energization of the Developer's facilities, the Utility will own, operate and maintain the equipment.

6.3.1.1.2 ***Cost Estimates***

Upon identification of the need for a communications and/or monitoring system(s), the Utility will provide the Developer with a cost estimate, which will identify billable costs and functional requirements.

6.3.1.1.3 ***Specification and Ordering Responsibilities***

After the Utility furnishes the Developer with communication system requirements and associated costs and responsibilities, the Developer shall be responsible for the procurement of all equipment and associated hardware for the Developer's end of the interconnection. The Utility will provide the Developer with equipment specifications and any unique design requirements. Additionally, the Utility will supply the Developer with a Utility-approved vendors list for the equipment. The Developer shall be the lead contact with the equipment vendor(s).

The Developer shall provide copies of all vendor bid proposals and any subsequent correspondence between the Developer and the equipment supplier(s) dealing with any proposed technical modifications to the Utility specified equipment as well as the equipment delivery schedules. Any vendor exceptions to the Utility supplied specification(s) will require the Utility's review and acceptance. The Utility's review of vendor bid proposals must be completed before purchase orders are placed for the equipment.

6.3.1.1.4 *Documentation*

The Developer shall submit to the Utility a complete set of vendor's equipment drawings throughout various phases of the project. The Utility will review this documentation and provide the Developer with comments regarding equipment modifications. Specific documentation requirements and review procedures are outlined in the Utility-supplied equipment specifications.

6.3.1.1.5 *Installation and Delivery*

Each party will be responsible for equipment installation at their respective ends. The Utility will not install equipment at the Developer's facility.

The Utility-end equipment will be delivered directly to a specified Utility Division Service Center. Upon receipt of the equipment, each party will be responsible for acceptance testing of equipment for their respective ends. The Developer shall test all equipment in accordance with Appendix 1, “IPP Protective Relay Communications and Monitoring Equipment Test Requirements.”

6.3.1.2 Remote Alarming, Control and Metering

Where protective relay communications systems are required, the Developer shall provide remote alarming of the systems’ "off-normal" conditions to a designated Utility location. This can be accomplished through a Utility RTU, if one will be located at the Developer's facility. If an RTU is not required at the Developer's facility, protective relay communication systems alarm information must be provided by alternate means.

In facilities where an RTU is required, the following status points at the facility are required to be monitored by the RTU (“breaker” corresponds to all interrupting devices in the facility that interconnect generation to the Utility system):

- Status of interconnecting breaker(s) and individual generator breakers (“a” switch indication)
- Breaker trouble (interconnecting breaker(s) only)
- Loss of relay DC
- Loss of relay AC potential
- Protective Relay cutoff switches (if any)
- Relay trouble
- Supervisory cutoff of devices controlled through the RTU (Local-Remote)

In addition, where an RTU is required, the Utility requires (through the RTU) control of all breakers in the facility that interconnect generation to the Utility system.

Depending on the MVA capacity of the facility, the Utility requires that various analog data points be monitored by the RTU. These points may include, but are not limited to, the following (also referenced in Section 6.2.3.3):

- Watts, vars, MWH, amperes of each unit within the facility
- Watts, vars, MWH, amperes of the total facility
- Bus voltage at which the plant is interconnected to the Utility

The RTU will be ordered by the Utility (typical lead time is approximately 8 to 12 weeks). Utility System Operations will need approximately 1 week to test, configure and ship the RTU’s to the site. The Utility will perform the RTU connections, point-to-point testing and commissioning. Communications and metering wiring required for SCADA inputs and power for the RTU shall be brought to the RTU by the Developer to the actual physical location where the RTU is to be mounted with enough slack that all terminations can be made cleanly. All wires are to be clearly marked as to their origin and final destination. The Developer will need to create point definition sheets associated with the system protection and control drawings, in accordance with Utility alarm and SCADA point definition guidelines. The point definition sheets will be used by the Utility System Operations Group to create termination sheets (T sheets), which the Developer can use to create the RTU external connection diagrams.

6.3.1.3 Spare Parts

The Utility **strongly recommends** that the Developer stock a complete set of spare parts. Loss of a protective relay communications system will compromise the reliability of the protective system, and the Developer will be forced to disconnect the generation from the Utility system until such time that the communications system is back in service.

6.3.2 Communications Media

6.3.2.1 Leased Communications Media

Leased telephone channels for protective relaying shall conform to the Bell Systems Technical Reference - PUB 41011-C6, Transmission Specifications For Voice Grade Private Line Audio Tone Protective Relay Channels.

Leased telephone channels for data shall conform to the Bell Systems Technical Reference - PUB 41004, Data Communications Using Voiceband Private Line Channels; and, PUB 41009, Transmission Parameters Affecting Voiceband Data Transmission - Measuring Techniques.

6.3.2.1.1 *Standards*

The Developer is responsible to ensure compliance with the most current version of the following standards.

> (IEEE Std. 487) - IEEE Guide for Protection of Wire-Line Communications Facilities Serving Electric Power Stations (IEEE Std. 367) -IEEE Guide for Determining the Maximum Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault.

6.3.2.1.2 *Liaison and Ordering Responsibilities*

Telephone channel circuit ordering and interface responsibilities with the telephone company(ies) has historically been the sole responsibility of the Developer, but results have frankly been terrible, as the Developer usually does not have the experience dealing with phone company processes and practices related to protection and SCADA circuits. Indeed this task can easily take the telephone company in excess of 12 weeks to engineer and install, from the time the substation building is ready to allow telephone company access to begin installation of circuits. The Utility can not emphasize enough the need to closely follow and manage this process, if the Developer wishes to avoid in-service date delays. Therefore, if the Developer agrees, the Utility will use their communications experts to order the communications circuits that are required for interconnect-related protection, SCADA, and metering, and manage that process to a successful conclusion, for all telephone channels that are routed for these purposes. If the Developer so agrees, Utility time and material costs will be billed to the Developer, and the circuits will be ordered as Utility circuits. The Utility will utilize its best efforts to manage this process, but takes no responsibility for delays caused by the phone company(ies). Note- this offer to order and facilitate communication circuit orders applies only to communications related to the interconnect protection, SCADA, and metering for telephone channels routed for these purposes which may include communication circulates that will be owned by the Utility or the Developer.

6.3.2.1.3 *Cost Estimates*

For protective relaying applications, the Developer is solely responsible to obtain communication channel installation and monthly rental charges from the appropriate telephone company(ies). The Utility will assume this responsibility, if applicable per section 6.3.2.1.2 above.

6.3.2.1.4 *Ground Potential Rise Considerations*

If high voltage special protection ("HVSP") equipment is required, as identified by Ground Potential Rise ("GPR") studies, the Developer will incur all expenses for such equipment. If the telephone company(ies) do not allow customer ownership of HVSP equipment, then it will be the responsibility of the Developer to procure HVSP equipment for both ends of the interconnection. The Utility will assume this responsibility, if applicable per section 6.3.2.1.2 above.

Where the local communications carrier's tariff(s) allow customer ownership of HVSP equipment, the Utility will negotiate directly with the telephone company(ies), at the Developer's expense, for ownership and maintenance arrangements for the Utility-end only. If HVSP equipment already exists at the Utility location, the Developer will be informed of this requirement at the outset of the project. The Utility will not estimate the cost of HVSP equipment.

The Utility will provide the short circuit information specific to the location for the Developer to determine the GPR at the Developer's location. The Developer's GPR calculations and associated results (including obtaining the E911 address, soil resistivity measurement data, ground grid resistance measurement data or ground grid resistance calculated values if new) shall be submitted to the Utility for review prior to ordering the leased telephone circuits.

6.3.2.1.5 *Notification Requirements*

The Utility shall be notified of the circuit type requisitioned via copy of the circuit order issued by the Developer to the telephone company(ies). The Developer shall notify the Utility a minimum of two weeks in advance of the telephone channel installation so that proper arrangements can be made to have a Utility representative present during telephone company installation of the leased circuit(s) at the Utility-end.

6.3.2.2 Privately Owned Communications Media

If it is technically and economically feasible to install privately owned fiber optic, hardwire, or power line carrier protective relay, and/or data communications systems, the Developer and the Utility shall mutually agree on the types of systems to be used and the engineering specification, procurement, and installation responsibilities and requirements.

Any communications system designed or proposed by the Developer shall conform to all applicable ANSI, IEEE, NEC, NESC, and Utility standards.

The Utility will have the right to review and accept all systems designed, specified, procured, and installed by the Developer or the Developer's agent.

6.3.3 Other Utilities

Where other foreign electric utilities are involved in the Developer's generation project, the Developer shall be responsible to coordinate the engineering, procurement and installation of protective relay communications and monitoring systems. The Developer shall be responsible for negotiating and/or obtaining any additional agreements or contract requirements.

7 INSPECTION, CERTIFICATION, TESTING, AND MAINTENANCE REQUIREMENTS

7.1 Inspection and Certification Requirements

The Developer's electrical equipment and interconnection wiring shall be in accordance with applicable portions of the NEC, NESC, and all other applicable codes, as required. The Developer shall obtain a written statement from the qualified New York State Licensed P.E. utilized to design the Developer's protection system, certifying that the Developer's facility, as designed and constructed, is in complete accordance with all applicable codes. This statement shall have the P.E.'s seal affixed on it. A copy of the statement shall be furnished to the Utility.

The Utility also requires the Developer to obtain certification that the Developer's electrical equipment and interconnection wiring is in accordance with all applicable codes, from an authorized electrical inspection organization acceptable to the Utility. Names of such organizations will be provided upon request. Once the Developer has selected one of the Utility-approved inspection organizations and the inspection process has been initiated, the selected inspection organization must be retained by the Developer throughout the inspection process until certification is granted. The Utility must be presented with written evidence showing that all electrical equipment and interconnection wiring at the Developer's facility has been inspected and certified by a qualified inspection organization **prior** to the beginning of initial inspection and testing.

7.2 Test Requirements

The Developer shall arrange for qualified personnel to perform calibration and functional tests on the fault and isolation protection systems, along with tests on CTs and VTs utilized in the protection systems, in accordance with typical Utility industry practices. The tests that shall be performed during the initial and periodic tests are detailed in Section 7.2.3. The Developer shall provide the name and qualifications of the individual(s) who will be performing the tests, for the Utility's acceptance.

7.2.1 Initial Inspection and Tests

Prior to the initial parallel operation of the Developer's equipment with the Utility system, or after modifications are made to plant already interconnected with the Utility system, Utility personnel must be present for the protective relay and associated equipment calibration and functional tests, as well as the inspection of the Developer's equipment. The Developer will be invoiced for the costs for Utility personnel to inspect and witness these tests. The Utility requires a minimum of **two (2) weeks** notice prior to witnessing the Developer's protection system calibration and testing.

It is **not** the Utility’s policy to lease test equipment or provide assistance during testing.

The Developer shall provide the Utility a copy of all certified test reports for the initial inspection and tests of the Developer's equipment. Certified test reports must be submitted to the Utility prior to synchronization of the Developer's generation with the Utility's system.

7.2.2 Periodic Tests

Periodic calibration and functional tests of the Developer's isolation protection and protection for detecting faults on the Utility system and within the plant are required on a four-year basis for microprocessor-based relays that include self-test algorithms, or on a biennial (once every two years) basis for all other relays. Copies of certified test reports for microprocessor-based relays that include self-test algorithms shall be submitted to the Utility every six years. Copies of certified test reports for all other relays shall be submitted to the Utility on a biennial basis. Also, a battery maintenance log (if applicable) shall be submitted to the Utility on a biennial basis.

For relays installed in accordance with the “NPCC Criteria for the Protection of the Bulk Power System”, maintenance intervals shall be in accordance with the “NPCC Maintenance Criteria for Bulk Power System Protection”.

In order for the Developer's testing and inspection to be considered certified and accepted by the Utility, it must be performed under the direction of a qualified New York State licensed Professional Engineer ("P.E."). Additionally, test results and Developer's equipment data must be stamped by the qualified P.E. witnessing or performing the checkout and testing. The Developer is responsible to ensure that the P.E. witnessing or performing equipment calibration and start-up testing on the Developer's behalf has an extensive background in this field.

Periodic tests may be witnessed by the Utility at the Utility's option in lieu of P.E. certified tests. The Utility also reserves the right to inspect any of the Developer's equipment upon prior notice.

7.2.3 Tests to be Performed

The following tests shall be performed for the initial and periodic tests:

7.2.3.1 Current Transformer Test (initial tests only)

Field verify that the CT ratio and polarity are correct (Most easily accomplished during assembly). Verify the integrity of the CT insulation and secondary circuit using a 500 volt megger, and check for proper secondary ground connection.

7.2.3.2 Voltage Transformer Test (initial tests only)

Field-verify that the VT ratio is correct. Verify that correct voltages are present at the switchboard locations. Verify the integrity of the VT insulation and secondary circuit using a 500 volt megger and check for proper ground connection.

7.2.3.3 Calibration Test

The purpose of relay testing is to verify that a relay will respond to the appropriate inputs in the required manner as determined by the setting. The actual input quantities must be applied to the relay in accordance with the manufacturer's instruction book. The input quantities shall be determined by the relay settings. The settings must be consistent with those submitted by the Developer and accepted by the Utility. When testing electromechanical relays with time dials, sufficient test points must be taken to define the relay curve. The calibration data shall be documented in a legible format and contain all pertinent relay data. (Utility test forms may be used and are available upon request.)

7.2.3.4 Functional Test

A protective relay cannot function by itself. It is reliant upon other equipment such as instrument transformers, auxiliary relays, circuit breakers, interconnecting cables and control power to perform its protective function. The purpose of functional testing is to verify that the overall operation of the relay and its associated equipment is in accordance with its intended design. Therefore, it is beneficial for the Developer to develop specific test procedures with well-defined parameters for use during testing.

The functional tests must, at a minimum:

a. Verify that end devices from each protective scheme operate from every possible source of trip potential (including, if applicable, confirmation that the communications system operates the transfer trip end devices).
b. Verify that the end device contacts complete the trip circuit to the breaker, actually trip the breaker, and operate all associated auxiliary relays in the close and trip circuit.
c. Check for correct operation of synchronism check relay, block of close, and block of reclose.
d. AC Control Circuit - Verify circuit breaker trips upon loss of ac control power.
e. DC Control Circuit - Verify correct operation of dc control devices in the absence of ac supply. Battery systems shall be checked for proper recovery time after a circuit breaker has been operated.

7.2.3.5 Battery Maintenance

Battery systems must be serviced and maintained on a regular basis by the Developer. Each battery should be visually inspected for corrosion, damage and level of electrolyte. Voltage and specific gravity readings shall be taken for each cell in accordance with manufacturer's instructions and properly documented in a battery maintenance log.

8 ACCEPTANCE FOR INTERCONNECTION

8.1 Requirements for Interconnection

The Utility will notify the Developer in writing that the Developer's facility is accepted for interconnection to the Utility's system only after **ALL** of the following items have been completed:

8.1.1 Protection Design

Formal Acceptance of the Developer's proposed protection design by the Utility.

8.1.2 PE Certification

Developer has obtained a written statement from a qualified New York State licensed P.E. certifying that the facility, as constructed, is in complete accordance with all applicable codes, with a copy of the certification provided to the Utility.

8.1.3 Certificate of Inspection

Developer's facility has been inspected and certified by a Utility-approved inspection organization, with a copy of the certification provided to the Utility.

8.1.4 Utility Inspection

The Utility has inspected and accepted the Developer's protection and interconnection equipment.

8.1.5 Testing Completion

Developer has satisfactorily completed all calibration and functional tests on the protection system(s), witnessed by the Utility.

8.1.6 Safety and Operating Procedures

The Developer is familiar with the Utility's safety and operating procedures, switching and tagging procedures, etc. Copies of these procedures will be provided by the Utility, and the Developer will be required to attend a scheduled training seminar conducted by the Utility.

8.7.1 Other

All other terms of the Agreement are satisfied (i.e., insurance, etc.)

8.2 Interconnection/Synchronization of Developer’s Facility

Upon receipt of the Utility's written acceptance of the Developer's facility for interconnection to the Utility system, the Developer shall provide a minimum of **two (2) weeks** prior written notice of the date that the facility will synchronize to the Utility system.

Just prior to interconnection with the Utility's system, the Developer shall verify that the rotational phase sequence of the Developer's voltage matches that of the Utility system.

Immediately after interconnection, a load test shall be performed to verify:

- The correct polarity and phasing of inputs to the directional relays under load conditions.
- The correct current and voltage magnitudes in the CT and VT secondary circuits, under load conditions.

8.3 Maintenance Requirements

The Developer's Facility Disconnect Switch, protection and control equipment, interrupting device and synchronizing and phasing equipment shall be maintained on a regular basis by qualified personnel in accordance with industry and/or manufacturer's practices. The Utility reserves the right to inspect such equipment after interconnection of the Developer's system. A maintenance schedule and log shall be maintained and made available for inspection by the Utility upon request.

8.4 Developer’s System Modifications

Subsequent to the Utility's Formal Acceptance and Acceptance for Interconnection for parallel operation of the Developer's facility, the Developer shall not make any modifications or additions to its system without review and Formal Acceptance by the Utility. The Developer shall furnish the Utility with all documentation clearly indicating the modifications or additions being proposed. The Utility must review and Formally Accept these proposed modifications or additions prior to their implementation.

The Developer shall implement any fault and/or isolation protection system modifications identified by vendor defect reports, which would upgrade the interconnection protection to published vendor specifications. Upgrades involving devices that are installed solely for the protection of the Developer's equipment may be implemented at the discretion of the Developer

9 ATTACHMENTS

The following attachments are included in the Bulletin for the Developer's use and reference:

Attachment 1	List of Information Required from Developer
Attachment 2	Independent Power Producer Generator Notice (Form NB-232)
Attachment 3	New York State Standardized Application for Single Phase Attachment of Parallel Generation Equipment 25 kW or Less
Attachment 4	New York State Standardized Application for Attachment of Parallel Generation Equipment above 25 kW up to 2 MW
Attachment 5	Generator Information Sheet
Attachment 6	Exciter Information Sheet
Attachment 7	Governor Information Sheet
Attachment 8	Figure 1: Single Phase Induction Generator One Line Diagram
Attachment 9	Figure 2: Three Phase Induction Generator One Line Diagram
Attachment 10	Figure 3: Synchronous Generator One Line Diagram
Attachment 11	Figures 4.1, 4.2 & 4.3: Methods of Grounding
Attachment 12	Shielded Cable Grounding Procedures for RTU/Tone Telemetry Systems
Attachment 13	Graph 1: Flicker Limitations, Distribution Standard A80
Attachment 14	NPCC Emergency Operating Criteria Underfrequency Load Shedding Curve
Attachment 15	Checkout Forms for Generation Protection by Type Tested and Approved Equipment
Attachment 16	Checkout Forms for Independent Power Producer Generation
Attachment 17	Utility Service Territory Maps

ATTACHMENT 1

INFORMATION REQUIRED FROM THE DEVELOPER

The Developer shall furnish **ALL** of the following information required to complete the Utility's Engineering Review Process:

*1. Utility Form NB-232
2. Project Schedule
*3. Site Plan
*4. Description of Operation
*5. One-Line Electrical Diagram of Complete Facility
*6. One-Line Relay Diagram
*7. Three-Line Relay Diagram or AC Elementary Diagram
8. Generator Elementary Control Diagram
*9. Generator, Exciter & Governor Information Sheets
10. Equipment Nameplate Data and Electrical Ratings for:
  a. Prime Mover(s)
  *b. Interface/Step-up Transformer(s)
  *c. Interrupting Devices (Breakers, Contactors, etc.)
  *d. Current Transformers
  *e. Voltage Transformers
  *f. Line/Disconnect Switches
  g. Capacitor Bank(s)
  h. Battery and Charger or Source of Power Supply to Protective Relays and Interrupting Devices
  i. Surge Arresters
  j. Other (as specifically requested)
11. Proposed Relay Types and Settings for Fault and Isolation Protection Schemes
12. Telemetering Information (When Applicable)
13. Protective Relay Communications and Monitoring Systems Information
14. Method of Excitation
*15. Minimum Site Load Without Generator On-Line
16. Generator Saturation Curve
17. Exciter Saturation Curve
18. Block Diagrams
19. Temporary Construction, Start-up & Station Service Power Information
20. Application for Non-Residential Electric and/or Gas Service NYSEG Form CD942)
21. Developer's Site Environmental Information
22. Regulatory Permits and Approvals
23. Additional Information as Required by the Utility for Completion of the Technical Reviews

NOTE:

1) Items listed above with asterisks (*) are required by NYSEG and RG&E to complete the Preliminary Technical Review.
2) Additional information will be requested from the Developer when facilities are to be constructed by the Developer and transferred to the Utility upon completion.

ATTACHMENT 2

Independent Power Producer Generator Notice (Form NB-232)

NYSEG RG&E Independent Power Producer Generator Notice

☐ Preliminary
☐ Final
☐ Revised

Customer Account No. ____________ IPP File No. ____________ Division ____________

Developer Name ____________

Developer Address ____________

Telephone No. Primary ____________ Alternate ____________

Proposed Generating Facility Location ____________

City/Town/Village ____________ County ____________ State ____________ Zip ____________

Service Information	Electrical Location	Rate
Service Size ____	Substation Source ____	PSC# ____
Utilization Voltage ____	Circuit No. ____	SC# ____
Phase ____	Line No. ____	Rate Code ____
Maximum Demand ____	Pole No. ____	Rev. Class ____
Transformer Size ____	Voltage & Phase available at nearest	Spec. Prov. ____
Line Ext. Required ____	connecting primary	Discount ____
Est. Cost to Serve ____	____	

Generator Information	Metering Information: NYSEG	Metering Information: Developer
Manufacturer ____		
Type ____		
Rated Output (KVA) ____	Type ____	____
Nameplate Voltage ____	Volts ____	____
Power Factor ____	Phase ____	____
Phase ____	Wire ____	____
Disconnect Device ____	KW ____	____
Prime Mover ____	RKVAH ____	____

General Information

Consultant ____________ Telephone ____________

Electrical Contractor ____________ Telephone ____________

Equipment Supplier ____________ Telephone ____________

Date Interconnection requested ____________

Accounting Information

Billing Name ____________ MBJO/AE No. ____________

Billing Address ____________ Account No. ____________

Billing Contact ____________ Telephone No. ____________

Remarks

Issued By ____________ Date Issued ____________
Project Manager - IPP Interconnections

Reorder forms from NYSEG Business Forms & Envelopes - Ithaca NB-232, 1/05

ATTACHMENT 3

NEW YORK STATE STANDARIZED APPLICATION FOR SINGLE PHASE ATTACHMENT OF PARALLEL GENERATION EQUIPMENT 25 KW OR LESS TO THE ELECTRIC SYSTEM OF

Utility:____

Customer:

Name: ______________________________ Phone: (___)__________

Fax: (___)____________

Email: ______________________

Address:______________________________ Municipality: ________________

Utility Account Number:______________________________

Agent (if any):

Name: ______________________________ Phone: (___)__________

Fax: (___)____________

Email: ______________________

Address:______________________________ Municipality: ________________

Consulting Engineer or Contractor:

Name: ______________________________ Phone: (___)__________

Address:______________________________

____

Estimated In-Service Date: ________________________________

Existing Electric Service:

Capacity: __________Amperes Voltage: __________Volts

Service Character: ( )Single Phase ( )Three Phase

Location of Protective Interface Equipment on Property:

(include address if different from customer address)

____

Energy Producing Equipment/Inverter Information:

Manufacturer: __________________________________

Model No. ________________ Version No. ________________

( )Synchronous ( )Induction ( )Inverter ( )Other_________

Rating: __________kW Rating: __________kVA

Generator Connection: ( )Delta ( )Wye ( )Wye Grounded

Interconnection Voltage: __________Volts

System Type Tested (Total System): ( )Yes ( )No; attach product literature

Equipment Type Tested (i.e. Inverter, Protection System):

( )Yes ( )No; attach product literature

Three line Diagram attached: ( )Yes

Installation Test Plan attached: ( )Yes

If applicable, Certification to UL 1741 attached: ( )Yes

Signature:

______________________________ ______________________________ ______________

CUSTOMER/AGENT SIGNATURE TITLE DATE

ATTACHMENT 4

NEW YORK STATE STANDARIZED APPLICATION FOR ATTACHMENT OF PARALLEL GENERATION EQUIPMENT ABOVE 25 KW UP TO 2 MW TO THE ELECTRIC SYSTEM OF

Utility:____

Customer:
Name: ______________________________ Phone: (___)__________

Fax: (___)____________

Email: ______________________

Address:______________________________ Municipality: ________________

Utility Account Number:______________________________

Agent (if any):
Name: ______________________________ Phone: (___)__________

Fax: (___)____________

Email: ______________________

Address:______________________________ Municipality: ________________

Consulting Engineer or Contractor:
Name: ______________________________ Phone: (___)__________

Address:______________________________

____

Estimated In-Service Date: ________________________________

Existing Electric Service:
Capacity: __________Amperes Voltage: __________Volts
Service Character: ( )Single Phase ( )Three Phase
Secondary 3 Phase Transformer Connection ( )Wye ( )Delta

Location of Protective Interface Equipment on Property:
(include address if different from customer address)

____

Energy Producing Equipment/Inverter Information:
Manufacturer: _________________________________
Model No. ________________ Version No. _____________
( )Synchronous ( )Induction ( )Inverter ( )Other_________
Rating: __________kW Rating: __________kVA
Rated Output: ____VA Rated Voltage: ____Volts
Rate Frequency: ____Hertz Rated Speed: ____RPM
Efficiency: ____% Power Factor: ____%
Rated Current: ____Amps Locked Rotor Current: ____Amps
Synchronous Speed: ____RPM Winding Connection:
Min. Operating Freq./Time:
Generator Connection: ( )Delta ( )Wye ( )Wye Grounded
System Type Tested (Total System): ( )Yes ( )No; attach product literature

Equipment Type Tested (i.e. Inverter, Protection System):
( )Yes ( )No; attach product literature
Three line Diagram attached: ( )Yes
Verification Test Plan attached: ( )Yes
If applicable, Certification to UL 1741 attached: ( )Yes

For Synchronous Machines:

Submit copies of the Saturation Curve and the Vee Curve
( )Salient ( )Non-Salient
Torque: _____lb-ft Rated RPM: _______
Field Amperes: ________ at rated generator voltage and current
and ________% PF over-excited
Type of Exciter: ____
Output Power of Exciter: ____
Type of Voltage Regulator: ______________________________________
Direct-axis Synchronous Reactance (X_d) _______ohms
Direct-axis Transient Reactance (X'_d) _______ohms
Direct-axis Sub-transient Reactance (X''_d) _______ohms

For Induction Machines:

Rotor Resistance (R_r)_____ohms Exciting Current ____Amps
Rotor Reactance (X_r)_____ohms Reactive Power Required:
Magnetizing Reactance (X_m)_____ohms ___VARs (No Load)
Stator Resistance (R_s)_____ohms ___VARs (Full Load)
Stator Reactance (X_s)_____ohms
Short Circuit Reactance (X''_d)_____ohms Phases:
Frame Size: ____________ Design Letter: ____ ( )Single
Temp. Rise: ____________ ^{O}C. ( )Three-Phase

For Inverters:

Manufacturer: _____________ Model:
Type: ___ ( )Forced Commutated ( )Line Commutated
Rated Output: _____Amps _____Volts
Efficiency: ______%

Signature:

______________________________ ______________________________________ _______________

CUSTOMER/AGENT SIGNATURE TITLE DATE

ATTACHMENT 5
Generator Information Sheet

GENERATOR INFORMATION

DATE ____________ DEVELOPER ____________
PROJECT NAME ____________

UNIT NO. ____________
MANUFACTURER ____________
UNIT SERIAL NO. ____________
WINDING CONNECTION ____________
DAMPER (Amortisseur) WINDING? ____________

KVA ______
KW ______
Hp ______
FREQUENCY ______
R.P.M. ______
GROUNDING RESISTANCE IN OHMS ______

Power Factor ______
VOLTAGE ______
CURRENT ______
No. of Phases ______
Neutral Grounded? ______

GENERATOR MODEL TYPE: (Select One)
ROUND ROTOR, ROUND ROTOR WITH DC OFFSET TORQUE COMPONENT, SALIENT POLE, TRANSIENT LEVEL, INDUCTION, CLASSICAL, OTHER (please specify) ____________

IF INDUCTION GENERATOR:

EFFICIENCY ______%
LOCKED ROTOR CURRENT ______Amp
SYNCHRONOUS SPEED ______RPM
MAGNETIZING INRUSH CURRENT IF ENERGIZED AT SYNCHRONOUS SPEED ______Amp
ROTOR RESISTANCE (Rr) ______*
ROTOR REACTANCE (Xr) ______*
MAGNETIZING REACTANCE (Xm) ______*
STATOR RESISTANCE (Rs) ______*
STATOR REACTANCE (Xr) ______*

EXCITING CURRENT ____________Amp
REACTIVE POWER REQUIRED:
a) ____________KVAR @ No Load
b) ____________KVAR @ Rated Load

FREQUENCY OF EXPECTED STARTS:
____________ Per Day
____________ Per Hour
T' ____________ sec.
T" ____________ sec.
X' ____________ *
X" ____________ *

IF SYNCHRONOUS GENERATOR:

X_d (SYNCHRONOUS) ____________*
X'_d (TRANSIENT) ____________*
X''_d (SUBTRANSIENT) ____________*
X_2 (NEGATIVE-SEQUENCE) ____________*
X_0 (ZERO-SEQUENCE) ____________*
X_q (SYNCHRONOUS) ____________*
X'_q (TRANSIENT) ____________*
X''_q (SUBTRANSIENT) ____________*
X (LEAKAGE) ____________*

T'_d (SHORT CIRCUIT, Transient) ______
T''_d (SHORT CIRCUIT, Subtransient) ______
T'_{do} (OPEN CIRCUIT, Transient) ______
T''_{do} (OPEN CIRCUIT, Subtransient) ______
T'_{qo} (OPEN CIRCUIT, Transient) ______
T''_{qo} (OPEN CIRCUIT, Subtransient) ______
T_a (WITH FIELD SHORTED) ______

INERTIA H ____________*
SPEED DAMPING D ____________*
ACCELERATION FACTOR ____________

MAXIMUM NUMBER OF UNITS ON BUS ___
MINIMUM NUMBER OF UNITS ON BUS ___
AVERAGE NUMBER OF UNITS ON BUS ___

GENERATOR WR^2 IN POUND-FEET SQUARED ____________
FLYWHEEL WR^2 IN POUND-FEET SQUARED ____________
PRIME MOVER WR^2 IN POUND-FEET SQUARED ____________
TOTAL WR^2 IN POUND-FEET SQUARED ____________

---

* VALUES ARE IN p.u., MACHINE KVA BASE

ATTACHMENT 6
Exciter Information Sheet

EXCITER INFORMATION

DATE ____________ DEVELOPER ____________
PROJECT NAME ____________

UNIT NO. ____________
MANUFACTURER ____________
REGULATOR TYPE ____________
MINIMUM DESIGN RESPONSE RATIO ____________
E_{FD} NOMINAL FIELD VOLTAGE ____________ VDC

EXCITATION SYSTEM MODEL: (Select One)

1981 IEEE TYPE AC1 ____
Modified TYPE AC1 ____
1981 IEEE TYPE AC2 ____
1981 IEEE TYPE AC3 ____
1981 IEEE TYPE AC4 ____
1981 IEEE TYPE DC2 ____
1981 IEEE TYPE ST1 ____

1981 IEEE TYPE ST2 ____
Modified 1981 TYPE ST2 ____
1981 IEEE TYPE ST3 ____
1968 IEEE TYPE 1 ____
1968 IEEE TYPE 2 ____
1968 IEEE TYPE 3 ____
1968 IEEE TYPE 4 ____

Modified 1968 TYPE 1 ____
Modified 1968 TYPE 4 ____
1968 IEEE TYPE 1S ____
1979 IEEE TYPE 2 ____
1979 IEEE TYPE 2A ____
1979 IEEE TYPE 3 ____

1979 IEEE TYPE 1 AND 1981 IEEE TYPE DC1 ____________
1979 IEEE TYPE 4 AND 1981 IEEE TYPE DC3 ____________
BUS OR SOLID FED SCR BRIDGE ____________
SIMPLIFIED EXCITATION SYSTEM MODEL ____________
OTHER (please specify) ____________

GAIN CONSTANTS AND FACTORS:

X_A	REGULATOR GAIN	____________
X_B	GAIN	____________
X_L	EXCITER FIELD CURRENT LIMIT GAIN	____________
X_C	RECTIFIER LOADING FACTOR	____________
X_D	DEMAGNETIZATION FACTOR	____________
X_E	SELF-EXCITED FIELD CONSTANT	____________
X_F	EXCITER FIELD CURRENT RATE COMPENSATION	____________
X_H	EXCITER FIELD CURRENT COMPENSATION	____________

TIME CONSTANTS:

T_A	REGULATOR	____________ sec.
T_D	REGULATOR LAG	____________ sec.
T_C	REGULATOR LEAD	____________ sec.
T_E	EXCITER	____________ sec.
T_F	STABILIZING	____________ sec.
T_R	REGULATOR INPUT FILTER	____________ sec.

VOLTAGE CONSTANTS AND SATURATION FACTORS:

V_{LR}	EXCITER FIELD CURRENT LIMIT VOLTAGE	____________ p.u.
V_{RMAX}	MAXIMUM INTERNAL REGUALTOR OUTPUT VOLTAGE	____________ p.u.
V_{RMIN}	MINIMUM INTERNAL REGULATOR OUTPUT VOLTAGE	____________ p.u.
$E_{FD}max$	VOLTAGE AT SATURATION POINT	____________ p.u.
$S(E_{FX}max)$	SATURATION FACTOR AT SATURATION POINT	____________ p.u.
$E_{FD}(0.75)$	VOLTAGE AT 0.75 OF SATURATION POINT	____________ p.u.
$S(0.75\ E_{FD}max)$	SATURATION FACTOR AT 0.75 OF SATURATION POINT	____________ p.u.

ATTACHMENT 7
GOVERNOR INFORMATION SHEET

GOVERNOR INFORMATION

DATE ____________ DEVELOPER ____________
PROJECT NAME ____________

UNIT NO. ____________
MANUFACTURER ____________

TURBINE GOVERNOR MODEL TYPE: (Select One)

GAS ____________
HYDRO ____________
STEAM ____________
1973 IEEE STANDARD ____________
OTHER (please specify): ____________

GAS TURBINE GOVERNOR:

W (Governor gain, ^{1}/Droop) ____________
Z (Governor mode, 1-Droop, D-ISO) ____________
T_{RATE} (Turbine Rating) ____________ MW
MAX (Limit) ____________ p.u.
MIN (Limit) ____________ p.u.
K_3 ____________
a (valve positions) ____________
c (valve positions) ____________
K_f ____________
K_5 ____________
a_{f1} ____________
b_{f1} ____________
a_{f2} ____________
b_{f2} ____________
c_{f2} ____________

X (Governor Time Constant) ____________ sec.
Y (Governor Time Constant) ____________ sec.
E_{TD} ____________ sec.
T_{CD} ____________ sec.
t ____________ sec.
E_{CR} ____________ sec.
b (valve positions) ____________ sec.
τ_f ____________ sec.
T_3 ____________ sec.
T_4 ____________ sec.
τ_t ____________ sec.
T_5 ____________ sec.
T_R (Rated Temperature) ____________ °F
K_6 (Minimum fuel flow) ____________ p.u.

HYDRO TURBINE GOVERNOR:

R (Permanent droop) ____________
r (Temporary droop) ____________
T_r (Governor time constant) ____________
T_f (Filter time constant) ____________
T_s (Servo time constant) ____________
±VELM (Gate velocity limit) ____________

G_{MAX} (Maximum gate limit) ____________
G_{MIN} (Minimum gate limit) ____________
T_W (Water time constant) ____________
A_t (Turbine gain) ____________
D_{TURB} (Turbine damping) ____________
q_{NL} (No-load flow) ____________

STEAM TURBINE GOVERNOR:

R ____________
V_{MAX} ____________ *
V_{MIN} ____________ *
D_t ____________ *

T_1 ____________ sec.
T_2 ____________ sec.
T_3 ____________ sec.

*Values are in p.u. on generator base

1973 IEEE STANDARD TURBINE GOVERNOR:

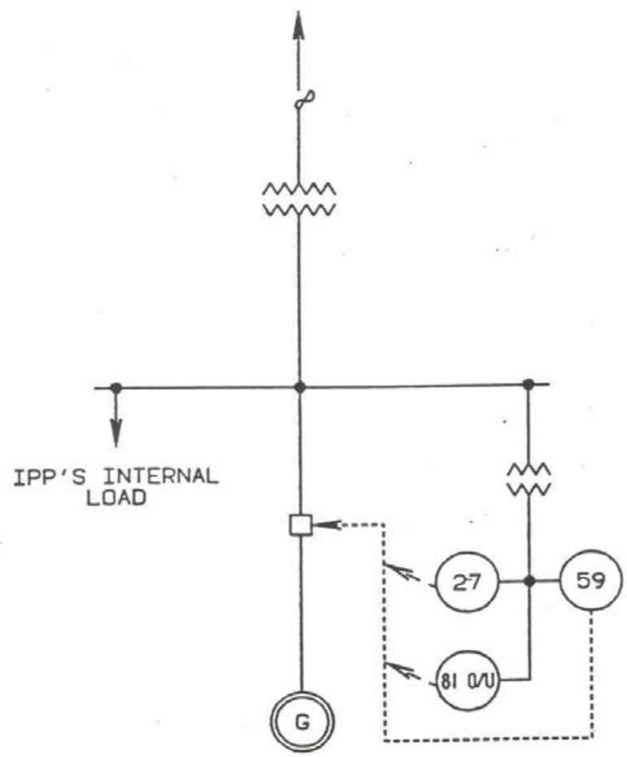
T_1 (Controller lag) ____________ sec.
T_2 (Controller lead compensation) ____________ sec.
T_3 (Governor lag) ____________ sec.
T_4 (Delay due to steam inlet volumes) ____________ sec.
T_5 (Reheater delay) ____________ sec.
T_6 (Delay due to IP-LP turbine, cross-over pipes and LP end hoods) ____________ sec.

K_1 ____________ ^{1}/p.u. regulation
K_2 ____________
K_3 ____________
P_{MAX} (Upper power limit) ____________
P_{MIN} (Lower power limit) ____________

ATTACHMENT 8
Typical Single Phase Induction Generator One-Line Diagram

FIGURE I

SINGLE - PHASE INDUCTION GENERATOR

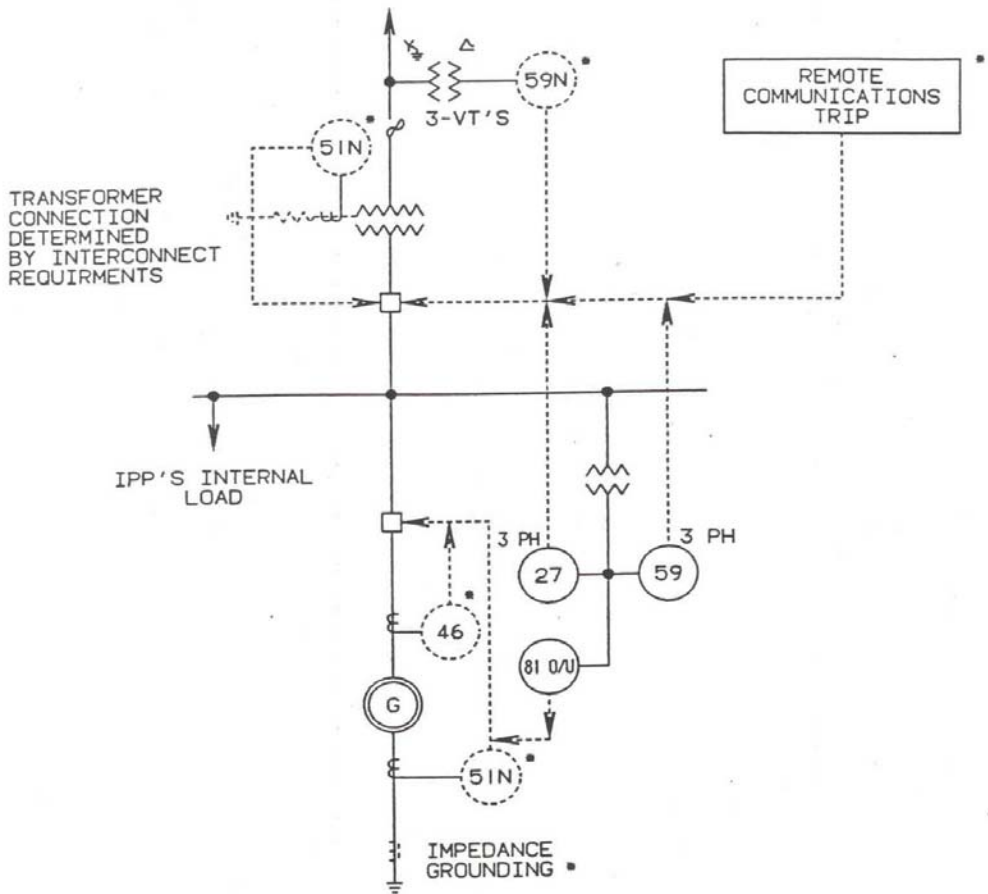


DEVICE	FUNCTION	PROTECTION
81 O/U	OVER/UNDER FREQUENCY	ISOLATION
27	UNDERVOLTAGE	FAULT AND ISOLATION
59	OVERVOLTAGE	ISOLATION

ATTACHMENT 9
Typical Three Phase Induction Generator One-Line Diagram

FIGURE 2

THREE - PHASE INDUCTION GENERATOR



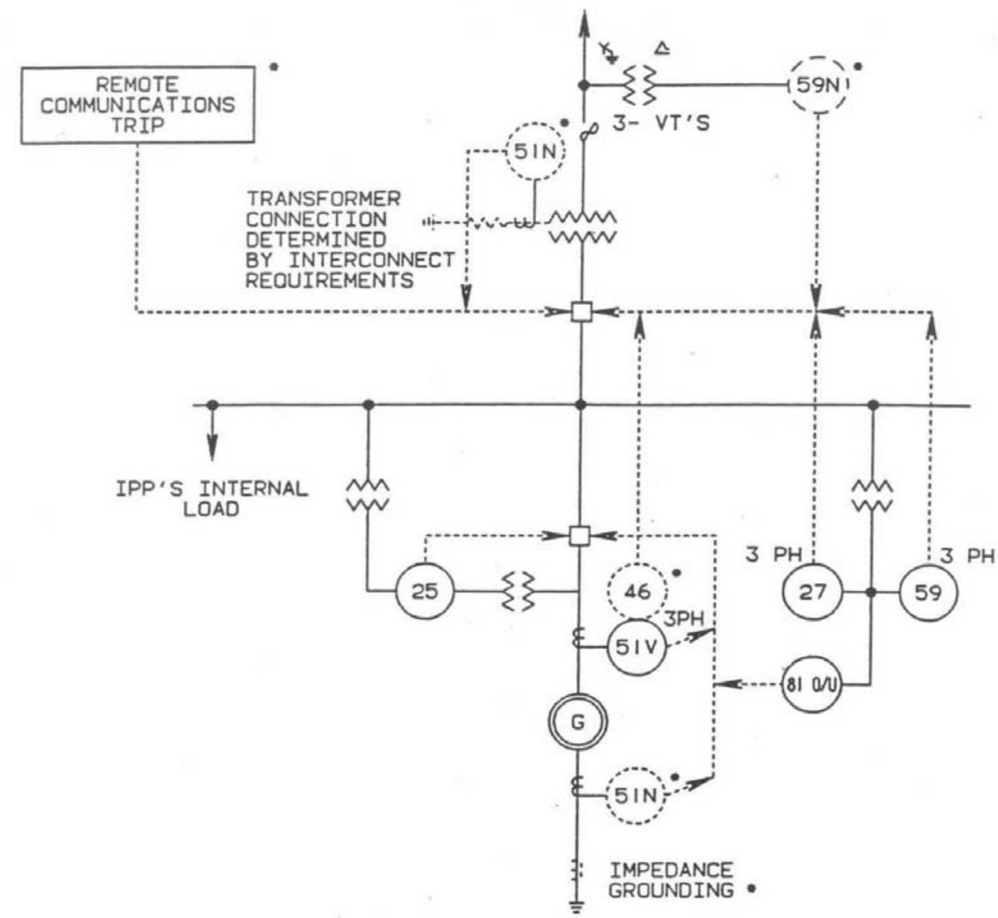
DEVICE	FUNCTION	PROTECTION
81 O/U	OVER/UNDER FREQUENCY	ISOLATION
27	UNDERVOLTAGE (3-PHASE)	ISOLATION AND FAULT
51N•	GROUND TIME-OVERCURRENT	PHASE-TO-GROUND FAULT AND OPEN CONDUCTOR
59	OVERVOLTAGE (3-PHASE)	ISOLATION
59N•	ZERO-SEQUENCE VOLTAGE	PHASE-TO-GROUND FAULT AND OPEN CONDUCTOR
46•	NEGATIVE SEQUENCE	OPEN CONDUCTOR

•NOTE: ADDITIONAL PROTECTION/EQUIPMENT THAT MAY BE REQUIRED, DEPENDING ON SPECIFICS OF INTERCONNECTION.

ATTACHMENT 10
Typical Synchronous Generator One-Line Diagram

FIGURE 3

SYNCHRONOUS GENERATOR



DEVICE	FUNCTION	PROTECTION
81 O/U	OVER/UNDER FREQUENCY	ISOLATION
27	UNDERVOLTAGE (3-PHASE)	ISOLATION
51V	PHASE TIME-OVERCURRENT W/VOLTAGE RESTAINT	3-PHASE AND PHASE-TO-PHASE FAULT
51N	GROUND TIME-OVERCURRENT	GROUND FAULT AND OPEN CONDUCTOR
25	SYNCHRONIZING	OUT-OF-SYNC CLOSE
59	OVERVOLTAGE (3-PHASE)	ISOLATION
59N•	ZERO-SEQUENCE VOLTAGE	GROUND FAULT AND OPEN CONDUCTOR
46•	NEGATIVE SEQUENCE	OPEN CONDUCTOR

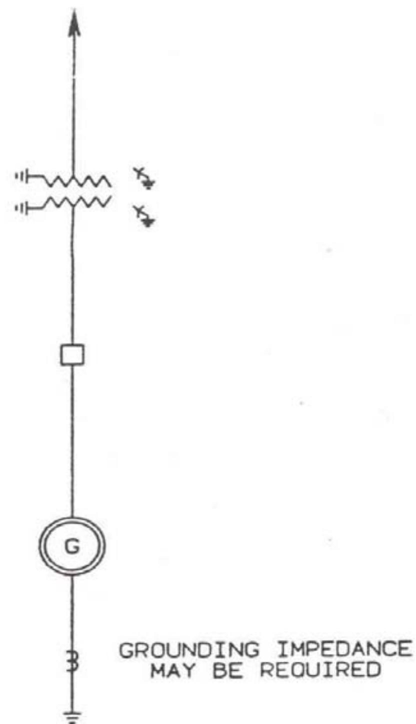
•NOTE: ADDITIONAL PROTECTION/EQUIPMENT THAT MAY BE REQUIRED, DEPENDING ON SPECIFICS OF INTERCONNECTION.

ATTACHMENT 11

Methods Of Providing Ground Sources

FIGURE 4.1

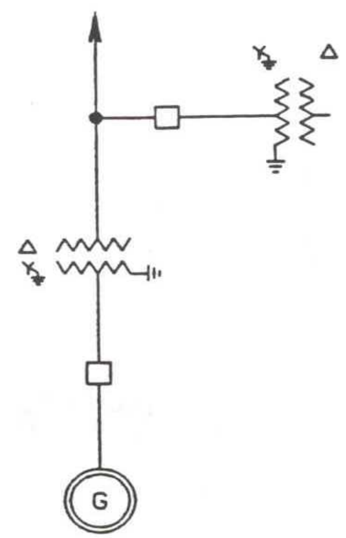
METHODS OF PROVIDING GROUND SOURCES



WYE-GROUNDED, WYE-GROUNDED STEP-UP TRANSFORMER
GENERATOR CONNECTED WYE-GROUNDED
(PREFERRED)

FIGURE 4.2

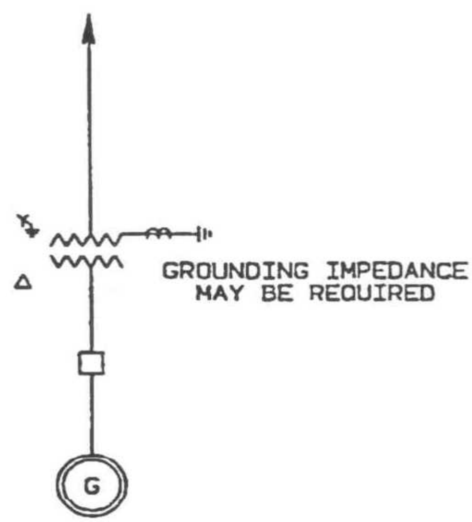
METHODS OF PROVIDING GROUND SOURCES



GROUNDING TRANSFORMER
WYE-GROUNDED/DELTA (SHOWN), OR ZIG-ZAG

FIGURE 4.3

METHODS OF PROVIDING GROUND SOURCES



WYE-GROUNDED, DELTA STEP-UP TRANSFORMER

ATTACHMENT 12

SHIELDED CABLE GROUNDING PROCEDURES FOR RTU/TONE TELEMETRY SYSTEMS

PURPOSE:

1. To prevent induced noise from causing telemetering inaccuracies.
2. To prevent shielded cable ground loops caused by improper installation. (Usually due to both ends of cable being grounded.)
3. To insure compliance with vendor specifications.

A. Shielding Practices for:

TRW - 9550 Remote Terminal Unit (RTU)
QEI - 3150 Remote Terminal Unit
QEI - 4150 Remote Terminal Unit
QEI - 4050 Remote Terminal Unit
QEI - STN 9150 Remote Terminal Unit
RFL - 9800 – 6700 Series Tone Telemetry

1. Insulate and secure the shielded cable ground wire at the RTU/Tone Equipment so that it does not touch other shields, earth ground, chassis ground, power supply references, etc. (See I-E above for example.

2. The source end of the shielded cable (usually at the transducer on a switchboard panel) should have the ground wire for the shields terminated to earth ground. The earth ground should be securely bonded to the station ground grid to dissipate induced noise.

B. General Practices for Installing Shielded Cable:

1. The signal wire pairs should remain twisted as close to the RTU/Tone Equipment and transducer termination as possible to help cancel the affects of induced noise.

2. The RTU/Tone Equipment and the transducer panels must be securely bonded to the station ground grid.

3. If the shielded cable path between the RTU/Tone Equipment and the transducer is not continuous (i.e. a demarcation panel is used for all RTU/Tone Equipment wiring) it is important to maintain continuity of the shield ground between the RTU/Tone Equipment and the transducer and not inject a new ground source at the cable junction.

   At this point where the two shielded cables meet between the RTU/Tone Equipment and transducer, dress each cable end as shown in item 1 above. Ensure that the shielded cable ground wires do not touch each other, earth ground or chassis ground. Terminate the twisted signal wires and associated shielded ground wire from the RTU/Tone Equipment on three termination points and connect the matching twisted signal wires and associated shielded ground wire from the transducer to the same termination points. This process will insure continuity of the signal and shielded ground between the RTU/Tone Equipment and the source.

4. If a new device or unique situation is being installed where grounding practices are unclear, contact NYSEG/RGE IPP/NUG Coordinator so that procedures may be reviewed.

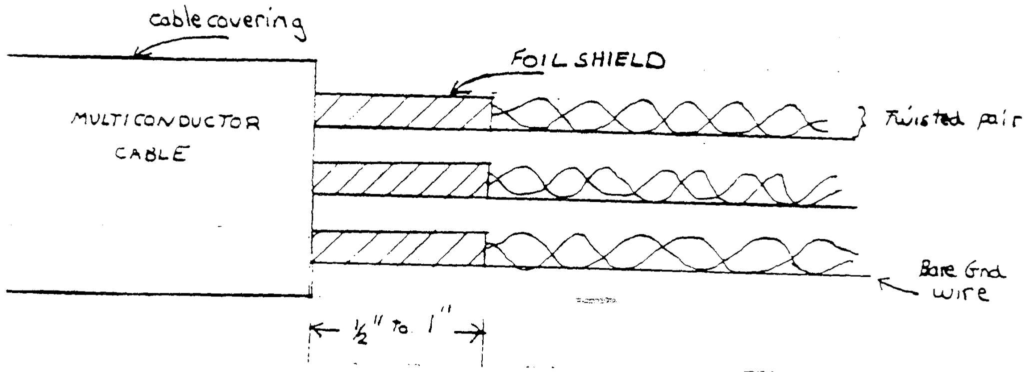
INSTALLING SHIELDED CABLE FOR TRANSDUCERS
(Single or Multiple Pairs)

ATTACHMENT 11

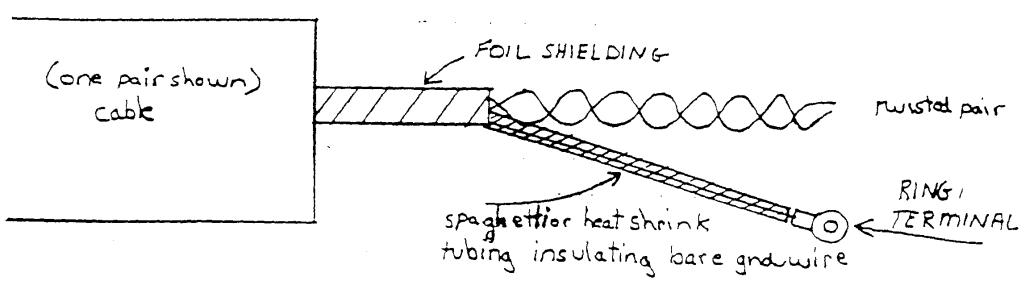
I. **INSTALLING SHIELDED CABLE FOR TRANSDUCERS**
(single or multiple pairs)

PURPOSE:
1. Keep all Foil Shielding insulated from each other.
2. Keep bare ground wire insulated from other foils, other ground wires and earth ground.

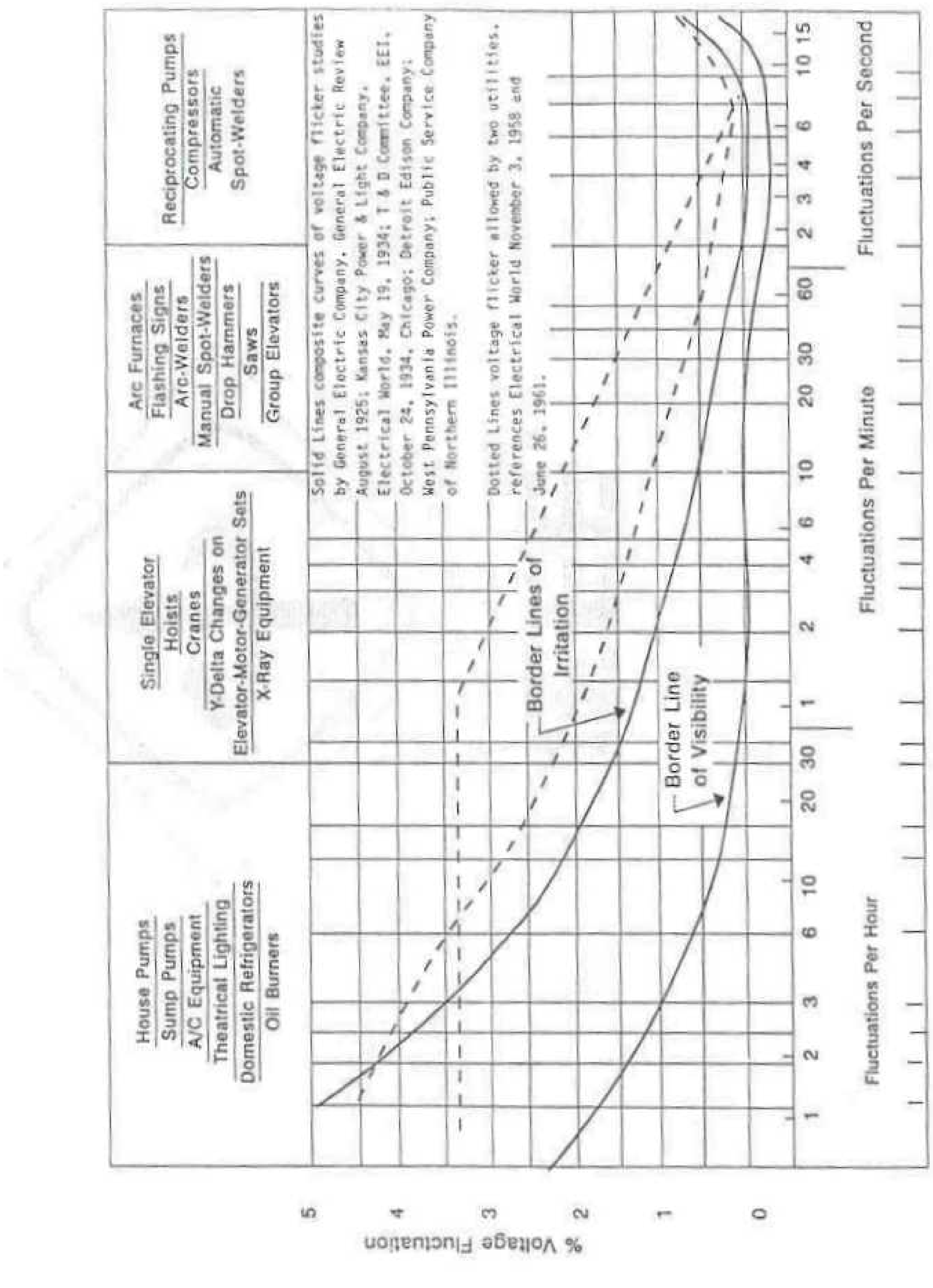
A. Typical shielded cable stripped back for installation.



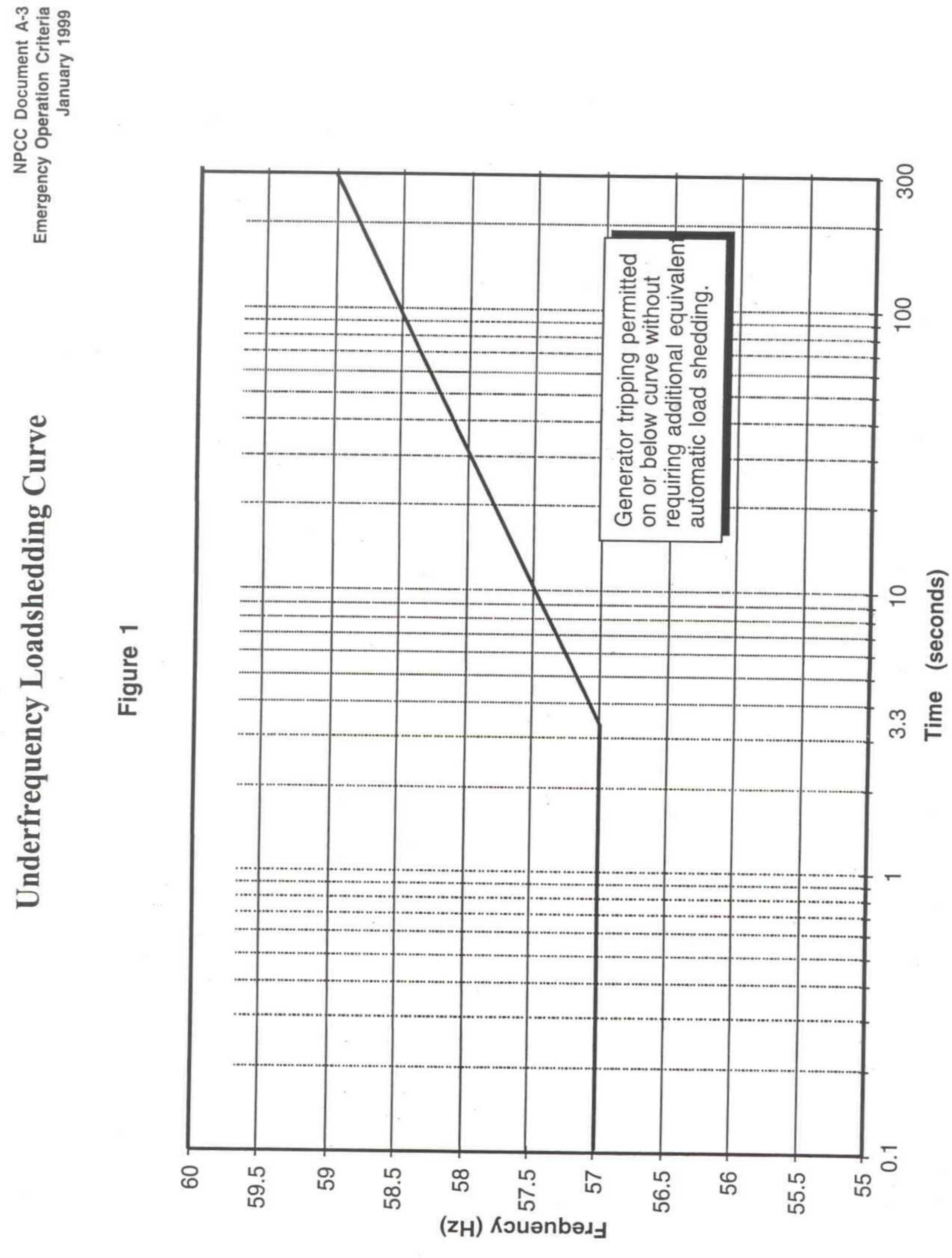
B. Apply insulation to each bare ground wire. Use ring type connector for terminating wire.



ATTACHMENT 13
Graph 1 - Flicker Limitations



ATTACHMENT 14
Underfrequency Load Shedding Curve



ATTACHMENT 15
Checkout Form For Generation Protected
By Type Tested And Approved Equipment

The customer is requested to submit the purposed equipment onto the standard utility field checkout form, to expedite the utility review and keep reimbursable costs and attendant schedule delays to minimum.

Division	
Local Utility Substation	
Project Name	
Address	
Phone	

		Satisfactorily Performed As Required? (√)	**Comments**
1.	SP&C Inspection Form		
2.	Functional Test		
3.	Load Break Disconnect Switch Operable and Lockable by Utility Personnel		
3a.	Switch Operating Mechanism and Mounting Structure Grounded		

Verified By:		**Review By:**		**Accepted By:**	
Date:		**Date:**		**Date:**	

Revision #:
Date:
By:

INSPECTION FORM

Verify that the following data is consistent with equipment installed by the Developer by a checkmark, otherwise supply correct data.

NOTE: N/A means not applicable.

Verification of Developer's Equipment Nameplate Data and Location

1. Generator(s)/Prime Mover(s)

Number of Units	

Generator Data	Unit #1	√	Unit #2	√	Unit #3	√	Comments
Type of Generator							
Manufacturer							
Firmware Version No.							
Rated Output (kVA)							
Rated Output (kW)							
Rated Voltage							
Rated Current							
Rated Frequency (Hz)							
Rated Speed (RPM)							
Power Factor (%)							
Phase (1 or 3)							
Connection							
Type of Grounding							

Grounding Ohms							

Prime Mover

	Unit #1	**√**	**Unit #2**	**√**	**Unit #3**	**√**	**Comments**
Type of Prime Mover							
Rated Output (HP)							
Rated Speed (RPM)							

PV Array (If Applicable)

	Unit #1	**√**	**Unit #2**	**√**	**Unit #3**	**√**	**Comments**
Type of Panels							
Rated Output (kVA)							
No. of Panels							

(Remainder of page intentionally left blank.

INSPECTION FORM (continued)

2. Transformer(s)

	Interface (GSU)	√	Comments
Owner			
Manufacturer			
Rated kVA			
Rated Primary Voltage			
Rated Secondary Voltage			
Connection – Primary			
Connection – Secondary			
Phase			
% Impedance			
Primary Fuse			
No. of Transformers			
Type of Grounding			
Grounding Ohms			
Location – See One Line			

3. Capacitor Bank

		√	Comments
Rated kVAR			
Phase			
Connection			

Location – See One Line			

4. Fault Interrupting Device(s)

	Main	√	Unit #1	√	Unit #2	√	Unit #3	√	Comments
Manufacturer									
Type									
Rated Voltage									
Rated Current									
Interrupting Current									
Operating Time									
Location – See One Line									

5. Disconnecting Switch

		√	Comments
Owner			
Manufacturer			
Type			
Rated Horsepower			
Rated Voltage			
Interrupting Current			
Location – See One Line			

INSPECTION FORM (continued)

6. Fault and Isolation Protection – (For Reference Only – Do Not Check)

Isolation Protection

		√		√		√		√	**Comments**
Function	27	√	59	√	81U		81O	√	
Trip Interrupt. Dev.	Bkr.	√	Bkr.	√	Bkr.	√	Bkr.	√	
Manufacturer									
Type									
VT/CT Ratio	-		-		-		-		
Tap (Pick-up)	106 V	√	132 V	√	59.3 Hz	√	60.5 Hz	√	
Time Dial	2 sec.	√	2 sec.	√	0.1 sec.	√	0.1 sec.	√	
Set Point	2 sec @ 106 V, 0.1 sec @ 60 V	√	2 sec@ 132 V, 2 cyc@ 165 V	√	0.1 sec @ 59.3 Hz	√	0.1 sec @ 60.5 Hz	√	
Location – See One Line									

7. Metering

Metering Option	**Single**		**Bi-directional**		**Double**	

ATTACHMENT 16
Checkout Form For Independent Power Producer Generation

Division	
Local Utility Substation	
Project Name	
Address	
Phone	

		Satisfactorily Performed As Required? (√)	**Comments**
1.	**SP&C Inspection Form**		
2a.	**Current Transformer Test**		
2b.	**Voltage Transformer Test**		
2c.	**Calibration Test**		
2d.	**Functional Test**		
2e.	**Load Test**		
3.	**Load Break Disconnect Switch Operable and Lockable by Utility Personnel**		
3a.	**Switch Operating Mechanism and Mounting Structure Grounded**		

Verified By:		**Review By:**		**Accepted By:**	
Date:		**Date:**		**Date:**	

CHECKOUT FORM FOR INDEPENDENT POWER PRODUCER GENERATION

Checkout forms for independent power producer generation facilitates, the completion of the review and acceptance of the Developer's generator interconnection. The checkout forms are divided into two parts: The "Inspection Form" and the "Requirements For Initial and Periodic Test."

PART 1

The Inspection Form serves as a vehicle for verifying that the Developer's installed equipment agrees with the design described in the documentation supplied by the Developer and accepted by the Utility. Indicated on the equipment forms is the equipment that the Utility expects the Developer to have installed. During the initial checkout (prior to synchronization with the Utility system), Utility personnel will verify that the information supplied on the Form is consistent with the equipment installed by the Developer.

PART 2

The Requirements For Initial and Periodic Test as designed to verify that the protection scheme operates as designed. The Utility has indicated several tests that are to be performed and documented by the Developer or his agent and witnessed by Utility division personnel.

When the Inspection Form has been satisfactorily completed and the proper tests have been witnessed and documented, the initial checkout is concluded. Final acceptance will be pending satisfactory review of the checkout forms by the Utility Engineering Department Verify that the following data is consistent wit equipment installed by the Developer by a checkmark; otherwise supply correct data.

NOTE: N/A means not applicable.

<u>Verification of Developer's Equipment Nameplate Data and Location</u>

1. Generator(s)/Prime Mover(s)

Number of Units	

Generator Data (Sync & Ind.)	Unit #1	√	Unit #2	√	Unit #3	√	Comments
Type of Generator							
Manufacturer							
Firmware Version No.							
Rated Output (kVA)							
Rated Output (kW)							
Rated Voltage							
Rated Current							
Rated Frequency (Hz)							
Rated Speed (RPM)							
Power Factor (%)							
Phase (1 or 3)							
Connection							

Type of Grounding							
Grounding Ohms							

Prime Mover

	Unit #1	√	Unit #2	√	Unit #3	√	Comments
Type of Prime Mover							
Rated Output (HP)							
Rated Speed (RPM)							

Induction Only

	Unit #1	√	Unit #2	√	Unit #3	√	Comments
Locked Rotor Current							
Synch. Speed (RPM)							
Efficiency (%)							

(Remainder of page intentionally left blank.)

INSPECTION FORM (continued)

2. Transformer(s)

	Interface (GSU)	√	Ground Bank	√	Comments
Owner					
Manufacturer					
Rated kVA					
Rated Primary Voltage					
Rated Secondary Voltage					
Connection – Primary					
Connection – Secondary					
Phase					
% Impedance					
Primary Fuse					
No. of Transformers					
Type of Grounding					
Grounding Ohms					
Location – See One Line					

3. Capacitor Bank

		√	Comments
Rated kVAR			
Phase			
Connection			

Location – See One Line			

4. Fault Interrupting Device(s)

	Main	**√**	**Unit #1**	**√**	**Unit #2**	**√**	**Unit #3**	**√**	**Comments**
Manufacturer									
Type									
Rated Voltage									
Rated Current									
Interrupting Current									
Operating Time									
Location – See One Line									

5. Disconnecting Switch

		√	**Comments**
Owner			
Manufacturer			
Type			
Rated Horsepower			
Rated Voltage			
Interrupting Current			
Location – See One Line			

INSPECTION FORM (continued)

6. Current Transformer(s)

For:		√		√		√		√	Comments
Manufacturer									
Type									
Accuracy Class									
Ratio – Prim/Sec									
Connection									
Location – See One Line									

7. Voltage Transformer(s)

For:		√		√		√		√	Comments
Manufacturer									
Type									
Accuracy Class									
Primary Voltage									
Secondary Voltage									
Connection – Prim/Sec									
Thermal Rating (VA)									
Location – See One Line									

8. Protective Relays

Fault Protection

		√		√		√		√	Comments
Function									
Trip Interrupt. Dev.									
Manufacturer									
Type									
VT/CT Ratio									
Tap (Pick-up)									
Time Dial									
Set Point									
Location – See One Line									

		√		√		√		√	Comments
Function									
Trip Interrupt. Dev.									
Manufacturer									
Type									
VT/CT Ratio									
Tap (Pick-up)									
Time Dial									
Set Point									
Location – See One Line									

8. Protective Relays (continued)

		√		√		√		√	Comments
Function									
Trip Interrupt. Dev.									
Manufacturer									
Type									
VT/CT Ratio									
Tap (Pick-up)									
Time Dial									
Set Point									
Location – See One Line									

9. Telemetering and Status Indication

		√		√		√		√	Comments
Function									
Manufacturer									
Type									
VT/CT Ratio									
Input Rage									
Output Range									
Scaling Resistor									

10. Battery and Charger

	Battery	√	Charger	√	Comments
Manufacturer					
Type					
Voltage Rating					
Ampere-Hour/Ampere Rating					

11. Surge Arresters

		√		√		√		√	Comments
Location									
Manufacturer									
Catalog Number									
MCOV Rating									

12. Miscellaneous Equipment

		√		√		√		√	Comments

Utility's Initial And Periodic Test Requirements For Independent Power Producer Generation Facilities

I. Interconnection of the Developer's equipment with the Utility system is contingent upon the successful completion of current and voltage transformer tests, as well as calibration and functional tests of the fault and isolation protection systems. The Developer must have these tests performed under the direction of a qualified New York State licensed Professional Engineer ("PE"), using test equipment appropriate for the various relays and equipment being tested and in accordance with typical utility industry practices. The Utility will witness all initial tests of the Developer's protection system. The Utility reserves the right to witness all periodic tests of the Developer's protection system in lieu of PE certified tests. The Utility requires two (2) weeks notice prior to witnessing initial or periodic tests. The following tests and maintenance shall be completed by the Developer.

A. <u>Current Transformer Test:</u>

Field-verify that the CT ratio and polarity are correct. (Most easily accomplished during assembly). Verify the integrity of the CT insulation and secondary circuit using a 500 volt megger, and check for proper secondary ground connection.

B. <u>Voltage Transformer Test:</u>

Field-verify that the VT ratio is correct. Verify that correct voltages are present at the switchboard locations. Verify the integrity of the VT insulation and secondary circuit using a 500 volt megger, and check for proper ground connection.

C. <u>Calibration Test:</u>

The purpose of relay testing is to verify that a relay will respond to the appropriate inputs in the required manner as determined by the setting. The actual input quantities must be applied to the relay in accordance with the manufacturer's instruction book. The input quantities shall be determined by the relay settings. The settings must be consistent with those submitted by the Developer and accepted by the Utility. When testing relays with time dials, sufficient test points must be taken to define the relay curve. The calibration data shall be documented in a legible format and contain all pertinent relay data. (Utility test forms may be used and are available upon request.)

D. Functional Test:

A protective relay cannot function by itself. It is reliant upon other equipment such as instrument transformers, auxiliary relays, circuit breakers, interconnecting cables, and control power to perform its protective function. The purpose of functional testing is to verify that the overall operation of the relay and its associated equipment is in accordance with its intended design. Therefore, it is beneficial for the Developer to develop specific test procedures with well-defined parameters for use during testing.

The functional tests must, at a minimum:

- Verify that end devices from each protective scheme operate from every possible source of trip potential (including, if applicable, confirmation that the communications system operates the transfer trip end devices).

- Verify that the end device contacts complete the trip circuit to the breaker, actually trip the breaker, and operate all associated auxiliary relays in the close and trip circuit.

- Check for correct operation of synchronism check relay, block of close, and block or reclose.

- AC Control Circuit – Verify circuit breaker trips upon loss of AC control power.

- DC Control Circuit – Verify correct operation of DC control devices in the absence of AC supply. Battery system shall be checked for proper recovery time after a circuit breaker has been operated.

E. <u>Battery Maintenance:</u>

Battery systems must be serviced and maintained on a regular basis by the Developer. Each battery should be visually inspected for corrosion, damage, and level of electrolyte. Voltage and specific gravity readings shall be taken for each cell in accordance with manufacturer's instructions and properly documented in a battery maintenance log.

II. Just prior to interconnection with the Utility system, the Developer shall verify that the rotational phase sequence of the Developer's voltage matches that of the Utility system:

III. Immediately after interconnection, a load test shall be performed to verify:

A. The correct polarity and phasing of inputs to the directional relays under load conditions.

B. The correct current and voltage magnitudes in the CT and VT secondary circuits, under load conditions.

Schedule F

Avangrid Networks Energy Control Center Switching and Tagging Rules and Procedures

TABLE OF CONTENTS

1.0 INTRODUCTION 2

1.1 Objective 2

1.2 Applicability 2

1.3 General Requirements 3

2.0 INSTRUCTIONS 10

2.1 Switching 10

2.2 Tagging 16

2.3 Non-Reclose Assurance Process 17

2.4 Live Line Permission Process 22

2.5 Clearance Process 25

2.6 Interconnections with Other Controlling Authorities, Utilities, Generators, or Customers 33

2.7 Delegation of Control – Controllership 35

2.8 Revisions to These Procedures 36

3.0 REFERENCES 36

4.0 DOCUMENT RETENTION 36

Attachment 1 - Definitions

Attachment 2 - Approved Tags

Attachment 3 - Approved Forms

1.0 INTRODUCTION

1.1 Objective

The purpose of this document is to provide personnel safety, maintain integrity of service, and protect apparatus used in the transformation, transmission, and distribution of electrical energy. This procedure shall be followed when isolating overhead and underground transmission circuits, overhead and underground distribution circuits, and substation apparatus.

The Energy Control Center (ECC) Operator will direct this process through the use of disconnecting devices, Tagging, and documentation. Authorized Persons shall be thoroughly familiar with this procedure and shall have a copy readily available for reference.

1.2 Applicability

This procedure applies to the AVANGRID Networks operating companies, Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating.

This procedure applies only to the performing or directing of work on electrical circuits or apparatus used in the transformation, transmission, and distribution of electrical energy. All individuals involved in such work shall be designated as an Authorized Person.

This procedure applies to all new work or installations as soon as any connection is made which would permit any part of the new work to be energized by the operation of a switch, open loop, or other device. From that time until the new work is placed in service or reported available for normal operation the connecting switch(es), open loops, or device(s) shall be appropriately Tagged at all times.

This procedure is for electric Isolation of equipment from the transmission and distribution electric grid. This procedure does *not* apply to the lockout and tagout of equipment that operates at or below 600 volts even if connected to the transmission or distribution system.

United Illuminating Exception: Three phase main breakers fed from padmounts, cages, transclosures, vaults, or underground transformers.

Attachment 1 contains the definitions of capitalized terms used throughout this procedure.

1.3 General Requirements

1.3.1 Responsibilities of Individuals

Only an Authorized Person shall implement any section of this procedure.

1.3.2 Enforcement of Procedure

A. It is the duty of every Authorized Person to rigidly enforce this procedure and to assist workers and others to understand and comply with it.

B. If at any time this procedure has not been strictly complied with, the ECC Operator shall be notified as soon as possible.

C. ECC Management, Operations Management, or their designee shall remove from the Authorized Person List any person who is not familiar with or fails to comply with this procedure and shall notify the department head on whose list the person's name appears.

D. Any person so removed from the Authorized Person List shall not be reinstated except on orders from the appropriate Operations Management head of the group involved.

1.3.3 Working on a Do Not Operate or Test Tagged Device

No work may be performed on a Do Not Operate (DNO) or Test Tagged device, e*xcept* work on a device that serves as a Protective Point may be permitted on the De-energized side of the device provided <u>all</u> of the following are met:

A. The device is not to be operated.

B. The apparatus is physically protected against closing.

C. Minimum approach distances are maintained.

1.3.4 Control of the Electrical System

The ECC Operator is the controller of all disconnecting devices associated with the transmission, distribution, substation, and network systems used to energize or de-energize circuits or apparatus except as follows:

A. When Controllership has been delegated by the ECC Operator.

B. Radial Side Taps*:* When an Authorized Person responds to an outage on a Radial Side Tap, the worker automatically has Controllership of that area. A switching order from the ECC Operator is not required to energize the area once a patrol has been completed by the worker and repairs are made. ECC will be updated after the outage is restored.

C. The parts of the AVANGRID Networks distribution system not under ECC control.

1.3.5 Duties and Responsibilities of the ECC Operator

The duties and responsibilities of an ECC Operator include but are not limited to the following:

A. Verifies that the Clearance Person is on the applicable Authorized Person List.

B. Directs Authorized Persons to operate switches or devices and install appropriate Tags for the work being performed.

C. Ensures the requested Zone of Protection is established and the circuit/apparatus involved are Isolated from all Known Sources of Energy operating at the primary voltage of the equipment being worked on.

D. Uses appropriate formal language to grant permission to take necessary precautions and work in the defined area.

E. Completes appropriate documentation.

F. Records all system configuration changes and Tags that have been ordered on or removed from equipment under their jurisdiction.

G. Issues, accepts the Release, and Transfers Clearances, Non-Reclose Assurances, and Live Line Permission and documents that information.

H. Issues and accepts release of Guarantees with Controlling Authorities, foreign utilities, generators, or customers.

1.3.6 Demarcation Line or Point (DL or DP)

At all locations where connections to adjacent utilities, customer facilities, or generators exist within the AVANGRID Networks Electric System, there shall be a mutually agreed upon line or point of change of ownership or Controllership identified, preferably consisting of a disconnecting device that is capable of providing a Visible Opening. Regardless of who is responsible for the work being done (*i.e.,* on which side of the line or point the work is occurring), the Controlling Authority shall give switching orders to an Authorized Person to operate and apply the appropriate AVANGRID Networks Tags. Existing agreements between AVANGRID Networks and connected facilities are not changed by this section.

A. Advance notice of the operation of DL or DP devices shall be provided to the AVANGRID Networks ECC Operators.

B. The DL or DP for foreign utilities, generators, or customers shall be identified on system one-line diagrams.

1.3.7 Inability to Release or Transfer

If a Clearance Person is unable to Release or Transfer a Clearance, Non-Reclose Assurance, or Live Line Permission, a Higher Authority with direct knowledge of the work being performed shall assume full responsibility and may Release or Transfer the Clearance to themselves through the ECC Operator. The Higher Authority shall also notify the original Clearance Person of the status of the Clearance at the earliest possible convenience.

1.3.8 Public Safety and Protection of the Public

When minimum approach distances on circuits energized at primary voltage cannot be maintained during work done (*e.g.,* crane work, scaffolding, etc.) by non-utility entities, an Authorized Person shall hold a Clearance for the line(s) or apparatus and the lines(s) or apparatus shall be grounded. It is the Clearance Holder's responsibility to establish and maintain contact with the public/contractor to ensure the equipment is returned to service when the work is completed and all personnel and equipment are in the clear. The Clearance Person shall be responsible for and maintain all documentation regarding meeting, discussions, job briefs, etc. This process shall be documented.

1.3.9 Removal of Circuit or Apparatus for Working Clearances

No circuits are to be removed from service for physical clearances, where minimum working clearances are to be compromised, without being Isolated, Tagged, tested De-energized, and Grounded using the Clearance Process.

1.3.10 Non-AVANGRID Networks Work Crews Working on AVANGRID Networks Apparatus

An Authorized Person must hold Clearance and direct switching for all work to be performed by non-AVANGRID Networks work crews protected by three phase main line devices such as station breakers, three phase reclosers, etc. Non-AVANGRID Networks work crews may switch under the direct supervision of an Authorized Switch Person.

1.3.11 Mutual Assistance in Storm Emergencies by Non-AVANGRID Networks Work Crews

Authorized AVANGRID Networks Employees who have been given control (Controllership) of distribution feeders, may direct non-AVANGRID Networks work crews to utilize their own protective procedures to protect themselves during storm restoration efforts.

1.3.12 Overlapping Zones of Protection

Overlapping Zones of Protection are not allowed when a Clearance is issued.

1.3.13 Qualifications of Authorized Persons

Authorized Persons shall have one or more of the qualifications listed below appropriate for the work they will perform. Workers who do not have the appropriate Authorized Person qualification shall not be issued Clearances, Non-Reclose Assurances, or Live Line Permission, and are not authorized to perform switching, except under direct supervision of an Authorized Switch Person who is at the location.

A. Clearance Person

1. Shall be an AVANGRID Networks employee or a contractor working for AVANGRID Networks.
2. Shall be trained in and knowledgeable of these Procedures, and shall have appropriate knowledge of the type of apparatus included within the Clearance.
3. Shall be issued Clearance, Live Line Permission, or Non-Reclose Assurance, but shall NOT perform switching and Tagging on AVANGRID Networks equipment unless also qualified as a Switch Person.

4. Shall have the ability to direct the performance of the work to be done.

B. ECC Operator

1. Shall be employed by AVANGRID Networks.

2. Shall be trained in and knowledgeable of these Procedures.

3. Shall have operational knowledge of the electrical system to be controlled.

C. Higher Authority

1. Shall be a management employee of AVANGRID Networks at the same or higher level of management of the Authorized Person in whose absence they may transfer or clear Tags.

2. Shall be trained in and knowledgeable of these Procedures, and shall have appropriate knowledge of the type of apparatus included within the Clearance.

3. Shall have the ability to direct the performance of the work to be done.

D. Switch Person

1. Shall be an AVANGRID Networks employee or a contractor working for AVANGRID Networks.

2. Shall be trained in and knowledgeable of these Procedures and shall have appropriate knowledge of the type of apparatus that is to be operated.

1.3.14 Approved Tags

All Tags used under these Procedures shall be completely filled in with all the information called for on the Tags.

Where applicable, Tags shall have a Switching Control Number assigned when ordered on by the ECC Operator or the name of the Authorized Person when ordered on by someone given Controllership.

A. Do Not Operate (DNO) Tag – Red

1. Shall be placed on Protective Points in the open position.

2. Shall ensure that a Tagged device will not be operated.

   Exception: Gang operated three-position disconnecting devices, may be operated (switched) to or from the Ground position without removal of the DNO Tag provided it does not result in the known introduction of potential through the device.

3. Shall be used for the protection of workers to establish a Zone of Protection when used for a Clearance when Live Line Work Methods are not possible. Application of test potential is not allowed within the Zone of Protection (*see* Test Tags).

4. Does not establish a Zone of Protection when using Live Line Work Methods but prevents closing of the device.

5. Does not imply that Grounds are installed (Grounds are required under a Clearance; *see* exceptions in Section 2.5.4(C)(3) Working without Grounds).

6. Only one DNO Tag shall be applied on a Protective Point; unless it is for a separate and adjacent work area. The ECC Operator controls issuance of Clearance to multiple Authorized Persons.

7. A Test Tag and a DNO Tag may only be applied on the same Protective Point if it is for a separate and adjacent work area.

8. A DNO Tag and a Caution Tag may be applied on the same device.

B. Non-Reclose Assurance (NRA) Tag – Orange

1. Placed on device(s) and associated supervisory controls to prevent automatic line re-energization.

2. May include enabling fast trip settings for arc flash protection (Hot Line Tag).

3. An NRA Tag and a Caution Tag may be applied on the same device.

C. Caution Tag – Yellow

1. Indicates that a device shall not be operated until the instructions documented on the Caution Tag are complied with.

2. May be placed on electrical apparatus in any position.

3. Shall not be used to establish a Zone of Protection.

4. May be used to indicate ground continuity through a closed disconnecting device, included closed permanently-installed ground switches.

5. May be used to identify devices that are not in their normal configuration or condition and/or are unsuitable for normal operation.

6. May be used on various relay applications as determined by the ECC Operator where worker protection is not required.

7. Shall be used to track System Operator Grounds where applicable.

D. Test Tag – Blue

Used when a Clearance is to be issued for work on a line, section of line, or equipment that may be test energized within the Zone of Protection.

1. Shall be placed on Protective Points in the open position.

2. Shall ensure that a Tagged device will not be operated.

   Exception: Gang operated three-position disconnecting devices, may be operated (switched) to or from the Ground position without removal of the Test Tag provided it does not result in the known introduction of potential through the device.

3. Shall be used for protection of workers to establish an initial Zone of Protection prior to the introduction of test voltage.

4. Shall have a number when issued by the ECC Operator or name when applied by someone given Controllership.

5. Only one Test Tag shall be applied on the same Protective Point unless it is for a separate and adjacent work area.

6. A Test Tag and a DNO Tag may only be applied on the same Protective Point if it is for a separate and adjacent work area.

7. A Test Tag and a Caution Tag may be applied on the same device.

8. When Test Tags are used, Grounds may be removed temporarily during testing. The Clearance Person shall keep the workers informed as to the conditions within the Zone of Protection at all times. Lines and equipment shall be worked as if energized, unless Grounded.

9. All personnel involved with work under a Test Tag Clearance shall ensure they do not directly or indirectly cause any condition or situation that might inadvertently result in De-energized lines becoming energized without first ensuring that all of the other personnel in the work area are made aware of the possibility of the line(s) becoming energized and given the time to move away from any potential danger zones. For this reason, <u>there will be only one Clearance Person per Test-Tagged Zone of Protection</u> (except for a brief period if a Test Clearance is transferred to another Clearance Holder occur).

2.0 INSTRUCTIONS

2.1 Switching

2.1.1 Authority to Operate

No device under the jurisdiction of the ECC Operator will be operated without permission from the ECC Operator except under the following circumstances:

A. Emergency Switching

Under emergency conditions that endanger life or property an Authorized Person can perform switching by opening apparatus to relieve the condition without first contacting the ECC Operator. This person performing the emergency switching assumes full responsibility for the switching and must relate all details to the ECC Operator as soon as possible. However, if a device is opened for any reason, it shall not be closed without receiving permission to do so from the ECC Operator to an Authorized Switch Person.

B. Within a Zone of Protection

When operating devices within a Zone of Protection the Clearance Person shall:

1. Notify others that have Clearance in the same Zone of Protection.

2. Direct all switching within the Zone of Protection.

3. Track the status of the device(s) by documenting the operation of device(s) on the Field Switching Order form.

4. When the Clearance is released, inform the ECC Operator of any remaining changes to devices within the issued Zone of Protection.

2.1.2 Safety Stop

In the event that either the ECC Operator or the Authorized Person determines that there is a safety or operational concern they shall safely stop all switching, communicate these concerns to each other and, if necessary obtain direction from their supervisor before proceeding.

2.1.3 Phasing Responsibilities

If phase integrity may have been compromised after work or repairs, the ECC Operator shall be notified and an order will be issued to perform phase check(s).

2.1.4 Switching Orders

The ECC Operator and the Switch Person are both accountable for the proper performance of the switching. Good communication during switching is paramount. It is the responsibility of the field person to establish and maintain a quality communication link with the ECC Operator. Communications between the ECC Operator and the Switch Person performing the switching and Tagging shall be person-to-person.

All switching and Tagging orders shall be given and received over recorded communications channels, using mutually agreed-upon voice medium (radio, cell phone, land line). All conveyances of switching orders will commence with an appropriate phrase denoting the commencement of switching such as **"This is a switching order. . ."**

All switching orders received from the ECC Operator shall use Three Part Communication. In all cases of unplanned switching, the switching step(s) shall be written down before they are performed.

2.1.5 Pre-Switching Brief

To provide the best check and balance possible a pre-switching brief will be initiated by the ECC Operator. The applicable items below will be included in every pre-switching brief.

- Determine whether communications will be done using radios or phones.
- Where applicable, confirm Switching Control Number and revision number of switching guide.

<u>Who</u>

- Exchange names and truck or phone numbers.

<u>What and Why</u>

- Identify what equipment is being switched.
- Explain why the switching is being performed.
- Provide an overview of the switching order(s).
- Identify any unusual switching schemes or relays.

<u>Where</u>

- Confirm the proper location of the switching.

<u>Understanding and Questions</u>

- Ask the Switch Person if they have any questions.
- Verify that the Switch Person understands the switching order(s).
- The ECC Operator will confirm that a pre-switch brief has been completed.

2.1.6 Switching Review

A. A switching review is required by the Switch Person prior to any switching procedure.

B. A review will consist of the following, where applicable:

- Review the associated station one line diagram and other circuit maps where possible.
- Identify and become familiar with the devices to be operated at that location.
- Determine or check the proper sequence for performing the required switching.
- Check for defective or abnormal apparatus that could prevent the switching from being performed safely or properly.
- Check for abnormalities in circuit or station loads/voltages, if applicable.
- If any issues are discovered, contact the ECC Operator to discuss concerns.

C. The Switch Person shall carry the switching order with them while executing the order.

D. The Switch Person shall verify the device identification number to be operated prior to switching the device.

E. The Switch Person will complete each step in the order listed in the switching orders. If this is not possible, they will report this to the ECC Operator immediately.

F. The Switch Person will report to the ECC Operator the completed switching steps and times as required.

2.1.7 Notification before Switching in a Substation

The Switch Person is responsible for notifying all affected personnel in the station or the personnel in charge of the work at the station before any switching is performed in that station.

2.1.8 Communications for Switching

Three Part Communication is required for all switching procedures.

A. The ECC Operator shall:

1. Issue instructions in a clear, concise and definitive manner.

2. Verify the recipient of the instruction repeats the information back correctly.

3. Acknowledge the response as correct or repeat the original instruction to resolve any misunderstandings.

4. Receive and repeat back the completion of the instruction.

B. The Switch Person shall:

1. Write down (if not provided in writing) each switching step.

2. Repeat back each switching step to the ECC Operator.

3. After receiving confirmation from the ECC Operator, begin switching in exactly the order as directed.

4. After the completion of switching, contact the ECC Operator and read back the switching order exactly as completed.

5. Verify and acknowledge the response as correct or repeat the original read back to resolve any misunderstandings.

C. Correct Terminology

When switching, both the Switch Person and the ECC Operator shall use proper terminology. Slang expressions and verbal short cuts shall not be used.

D. Unclear Switching Order

If any switching order is not clear due to terminology or communications system interference, neither the ECC Operator nor the Switch Person shall assume what the other party said. The message shall be repeated until it is understood.

2.1.9 Responsibilities

When directed to conduct any switching, the Switch Person shall be responsible to perform the following;

A. Check all switches to be in the fully open or fully closed position on all phases.

B. Check any switch attachment/component to be in the proper position before and after switch operation and report back to the ECC Operator any abnormalities that conflict with the anticipated state.

C. Check all circuit breakers that are operated to be open or closed utilizing position indicators, control lights, indicating meters, and potential lights as applicable.

D. Place locks and Tags on apparatus at the proper location as applicable and as directed.

E. Anticipate the effects when performing a particular switching operation.

F. Properly record/report alarms, relay targets, and device operations.

2.1.10 Testing and Grounding – Gang Operated Ground Switches

At locations that have gang operated Ground switches the line shall be tested De-energized with an approved testing device before closing the Ground Switch.

Exception: At locations that have gang operated Ground switches where testing with a high voltage tester cannot be performed or is not practicable, the following procedure shall be used as applicable:

A. Before a line/apparatus is De-energized and Isolated, voltage indication shall be checked at all ends of the line by live line indication and/or voltage readings from the station control panel and via Supervisory Control and Data Acquisition (SCADA), if available.

B. The line/apparatus shall then be De-energized and the disconnecting means opened, locked opened, and Tagged.

C. Check the line/apparatus De-energized at all ends of the line with live line indication, voltage readings, or open indication (Gas Insulated Switchgear (GIS)) from the station control panel and by the Energy Management System (EMS), if available.

2.1.11 Draw-out/Rack-out Type Circuit Breakers

When draw-out type circuit breakers are removed or inserted, the breaker shall be in the open position. The control circuit shall also be rendered inoperative (*e.g.,* removing control power fuses) if the design of the equipment permits.

2.2 Tagging

2.2.1 Locking/Unlocking and Tagging Devices

Each manually operated primary voltage switch with an operating rod shall normally be locked when in the open or closed position. The switch shall be unlocked only during the time it is being operated. If a switch cannot be securely locked, the ECC Operator shall be notified immediately. Tag shall be placed on the lock, or in appropriate Tag holders (*e.g.,* pole banner or other provisions). A Protective Point when so Tagged may or may not be energized.

A. All information pertinent to the placing of a Tag shall be filled in by the person placing the Tag before it is attached.

B. No erasures on a Tag are permitted.

C. No Tag may be used more than once.

2.2.2 When Accessible to the Public

When a switching device is accessible to the general public the Tags shall be placed at the locking provision or shall be located at a sufficient height from the ground to discourage unauthorized removal.

2.2.3 Motor Operated Switches

Motor operated switches that are opened as an Isolation point shall be rendered inoperable either by decoupling or removing control power to prevent closing by operation of any automatic, local, or remote control switches.

2.2.4 Tagging of Non-Gang Operated Devices

A single Tag is required to be applied to stick-operated switches, open loops/jumpers, fuses or fused cutouts used to Isolate apparatus. When Tagging a structure the Tag should be made obvious for easy identification. If the fuses or fused cutouts are removed (lifted out), the DNO or Test Tag must still be placed at the Isolation point (*e.g.,* using a pole banner).

2.2.5 Tagging of Visible Openings

The device providing the Visible Opening to establish a Zone of Protection shall be Tagged.

2.2.6 Tagging of Elbows

The device providing the Visible Opening to establish a Zone of Protection (the elbow) shall be Tagged.

2.2.7 Metal-Clad Switchgear

The device providing the Visible Opening is the Protective Point for the Isolation established and the racking mechanism shall be Tagged.

2.2.8 Tagging of Grounds

Where applicable, only System Operator Grounds (*see* definition of Ground) will be Tagged. A single Caution Tag shall be applied on the grounding device or at the location that the Grounds are applied.

2.3 Non-Reclose Assurance Process

Non-Reclose Assurance (NRA) is not a Clearance and no circuit or apparatus should be considered De-energized.

NRA provides an assurance from the ECC Operator to an Authorized Person that a line will not be manually or automatically re-energized. This may also include enabling fast trip settings (Hot Line Tag) for arc flash protection if so requested.

NRA shall not be issued during protective relay testing or any other condition which causes the protection package of an associated line or circuit to be altered. Likewise, protective relay testing shall not be allowed on a line or circuit for which NRA has been issued.

Whenever overhead repairs cannot be performed using Live Line Work Methods or NRA and Grounds are required for worker protection, the Clearance process will be used.

2.3.1 Requesting the Non-Reclose Assurance

The Authorized Person shall communicate the following information at the time of the request:

A. Name of Authorized Person requesting the NRA.

B. Work site location.

C. Transmission or distribution circuit device(s) on which reclosing needs to be defeated.

D. Whether or not fast trip or Hot Line Tag is required to be enabled.

E. Scope of work to be performed.

2.3.2 Preparation of the Non-Reclose Assurance

A. The ECC Operator or person requesting the NRA shall define or confirm the devices necessary for their work. The ECC Operator shall Tag or cause to be Tagged all devices and associated local and supervisory controls (SCADA) necessary to defeat automatic reclosing.

B. On recloser controls that are equipped with a fast trip feature (Hot Line Tag), this shall be enabled upon request from the Authorized Person.

C. When the automatic reclosing feature of a device is disabled during the course of work on energized equipment or circuits, a Tag shall be placed at the reclosing device location. When the automatic reclosing feature of a device is disabled electronically either locally or by SCADA no physical Tag is required in the field if the system provides for ALL of the following:

1. At the SCADA operating point (Control Center)

- A signal is received by the ECC Operator confirming that the disabling operation has occurred at the reclosing device location, AND
- A Tag (electronic screen Tag) is used to inform the ECC Operator that a disabling operation has been initiated, AND
- The electronic screen Tag must be removed before action is taken to re-enable the automatic reclosing feature. This is commonly known as a control inhibit Tag.

2. At the reclosing device location (field or substation)

- The reclosing feature is disabled in such a manner as to prevent manual override of the normal control by any potential on-site operator, OR

- A signal, flag, or other display is used in such a manner as to alert any potential on-site operator that the reclosing feature has been disabled.

2.3.3 Issuing the Non-Reclose Assurance

An NRA can only be issued after the reclosing control(s) for a specific circuit have been placed in the non-reclose position and the necessary Tags placed.

NRA shall be issued by the ECC Operator and acknowledged by the Authorized Person utilizing the proper formal language and Three Part Communication techniques. Prior to issuing an NRA to the Authorized Person(s) the ECC Operator shall:

A. State the Switching Control Number where applicable.

B. Specify the devices that have automatic reclosing defeated.

C. State (formal statement) that NRA is being given to the Authorized Person for the specific circuit requested.

2.3.4 Working under a Non-Reclose Assurance

A. The Authorized Person(s) to whom the NRA has been issued has the responsibility to inform the ECC Operator or the person who has assumed Controllership of any conditions that may have caused the device to operate.

B. When a device on which NRA has been given opens, it SHALL NOT be re-energized until the Authorized Person to whom the NRA was issued reports to the ECC Operator that all workers and equipment are in the clear, that the Authorized Person temporarily releases their NRA, and they agree that the line or equipment may be re-energized.

C. The breaker(s) or device(s) shall not be restored to the automatic reclose position until the NRA has been released.

D. An NRA issued by the ECC Operator may be transferred using the Transfer process.

2.3.5 Multiple Persons Working within the Non-Reclose Assurance

When multiple Authorized Persons must work on the same circuit, there are two options available. Only ONE set of Tags will be used on the same circuit.

A. Option One: Working under someone else's NRA

1. Separate crews can work under one NRA issued to a single Authorized Person if the crews comprise a group of people working in a coordinated manner to accomplish a task on the same circuit under the direction of a single Authorized Person.

2. The ECC Operator is not notified of this arrangement.

3. The Authorized Person is responsible for the safety and work performed by all people working under their NRA.

B. Option Two: Obtain NRA through the ECC Operator

This option is not intended to be used to perform a Transfer of work.

This option shall be followed when multiple crews work independently or jointly under the same NRA (one set of Tags with multiple NRAs issued) provided the following requirements are met:

1. The existing switching and Tagging is adequate for the additional work at all times.

2. Issuance of another NRA shall be permitted only with the knowledge and authorization of the ECC Operator. The ECC Operator shall notify all existing NRA holders of the additional Authorized Person(s) being added.

3. The ECC Operator shall track the names of all Authorized Person(s) under the same NRA.

4. Each Authorized Person shall release their NRA with the ECC Operator when their work is completed.

5. Each Authorized Person shall explain clearly to the ECC Operator all changes and/or repairs made by them.

6. While personal safety is the responsibility of each individual worker, the Authorized Person is responsible for the safety and work performed by the people under their immediate direction.

2.3.6 Releasing a Non-Reclose Assurance

A. Upon completion of work, the NRA shall be released by the Authorized Person and acknowledged by the ECC Operator utilizing the proper formal language and Three Part Communication techniques.

B. After the release of an NRA, if additional work is required, the ECC Operator may Re-Issue the NRA to the same or another Authorized Person.

2.3.7 Re-Issuing a Non-Reclose Assurance

An NRA may be Re-Issued to an Authorized Person that previously released an NRA only through the ECC Operator. The Tags remain in place and the same Switching Control Number is used where applicable.

2.3.8 Transferring a Non-Reclose Assurance

Under this process the work can continue.

A. Prior to contacting the ECC Operator, both the existing and the new Authorized Person shall conduct a comprehensive job transfer brief covering the job and worker status.

B. The Authorized Person contacts the ECC Operator and informs them that he has conducted the briefing with the new Authorized Person and requests the Transfer of NRA.

C. The new Authorized Person contacts the ECC Operator and is issued the NRA by the ECC Operator.

D. The original Authorized Person shall surrender their NRA with the ECC Operator.

2.4 Live Line Permission Process

Live Line Permission (LLP) is not a Clearance and no line or equipment should be considered Dead.

Under an LLP the ECC Operator grants permission to an Authorized Person to work on a De-energized line or equipment utilizing Live Line Work Methods.

The ECC Operator SHALL NOT energize the work area until the Authorized Person to whom the LLP was issued has been contacted by the ECC Operator and has reported that all workers and equipment are in the clear and that the line or equipment can be energized.

Whenever overhead repairs cannot be performed using Live Line Work Methods or NRA and Grounds are required for worker protection, the Clearance process will be used.

2.4.1 Requesting the Live Line Permission

The Authorized Person shall communicate the following information at the time of the request:

A. Name of Authorized Person requesting the LLP.

B. Work site location.

C. Transmission or distribution circuit on which Live Line Work Methods are being performed.

D. Scope of work to be performed, and the devices desired to create a De-energized area.

2.4.2 Preparation of the Live Line Permission by the ECC Operator

A. Whenever Live Line Work Methods are used to perform work in a De-energized area the ECC Operator will track and control switches that could re-energize the area if closed.

B. Due to the nature of work and the Live Line Work Methods being employed normally open switches will not be Tagged.

C. DNO Tags shall be installed on normally closed source devices that are found or ordered opened to sectionalize the outage area. DNO Tags placed for this purpose do not establish a Zone of Protection. Electronic tags may be used on devices opened via SCADA for this purpose.

D. If it is determined that work cannot safely be performed using Live Line Work Methods, the Clearance process shall be used.

2.4.3 Issuing the Live Line Permission

LLP shall be issued by the ECC Operator and acknowledged by the Authorized Person utilizing the proper formal language, pre-switch brief and Three Part Communication techniques. Prior to issuing LLP to the Authorized Person(s) the ECC Operator shall:

A. State the Switching Control Number where applicable.

B. Specify the Protective Points of the LLP.

C. Specify the affected circuit(s).

2.4.4 Working Under a Live Line Permission

A. A circuit SHALL NOT be energized until the Authorized Person to whom the LLP was issued has been contacted by the ECC Operator and has reported that all workers and equipment are in the clear and that the line or equipment can be energized.

B. An LLP issued by the ECC Operator may be transferred using the Transfer process.

2.4.5 Multiple Persons Working Within the Live Line Permission

When multiple Authorized Persons must work on the same circuit, there are two options available. Only ONE set of Tags will be used on the same circuit.

A. Option One: Working Under someone else's LLP

1. Separate crews can work under one LLP issued to a single Authorized Person if the crews comprise a group of people working in a coordinated manner to accomplish a task on the same circuit under the direction of a single Authorized Person.

2. The ECC Operator is not notified of this arrangement.

3. The Authorized Person is responsible for the safety and work performed by all people working under their LLP.

B. Option Two: Obtain LLP through the ECC Operator

This option is not intended to be used to perform a Transfer of work.

This option shall be followed when multiple crews work independently or jointly under the same LLP (one set of LLP Tags with multiple LLPs issued) provided the following requirements are met:

1. The existing switching and Tagging is adequate for the additional work at all times.

2. Issuance of another LLP shall be permitted only with the knowledge and consent of the ECC Operator.

3. The ECC Operator shall track the names of all Authorized Person(s) under the same LLP.

4. Each Authorized Person shall release their LLP with the ECC Operator when their work is completed.

5. Each Authorized Person shall explain clearly to the ECC Operator all changes and/or repairs made by them.

6. While personal safety is the responsibility of each individual worker, the Authorized Person is responsible for the safety and work performed by the people under their immediate direction.

2.4.6 Releasing a Live Line Permission

A. Upon completion of work, the LLP shall be released by the Authorized Person and acknowledged by the ECC Operator utilizing the proper formal language and Three Part Communication techniques.

B. After the release of an LLP, if additional work is required, the ECC Operator may Re-Issue the LLP to the same or another Authorized Person.

2.4.7 Re-Issuing a Live Line Permission

An LLP may be Re-Issued to an Authorized Person that previously released an LLP only through the ECC Operator. The Tags remain in place and the same Switching Control Number is used where applicable.

2.4.8 Transferring a Live Line Permission

Under this process the work can continue.

A. Prior to contacting the ECC Operator, both the existing and the new Authorized Person shall conduct a comprehensive job transfer brief covering the job and worker status.

B. The Authorized Person contacts the ECC Operator and informs them that he has conducted the briefing with the new Authorized Person and requests the Transfer of LLP.

C. The new Authorized Person contacts the ECC Operator and is issued the LLP by the ECC Operator.

D. The original Authorized Person shall surrender their LLP with the ECC Operator.

2.5 Clearance Process

Whenever overhead repairs cannot be performed using NRA or Live Line Work Methods and Grounds are required for worker protection, the ECC Operator will provide an Isolated Zone of Protection from all Known Sources of Energy through the use of DNO or Test Tags installed on Protective Points to establish a Zone of Protection.

2.5.1 Requesting the Clearance

The person requesting the Clearance shall define or confirm the Zone of Protection to the ECC Operator for all isolating devices necessary to Isolate the circuit or apparatus being worked on from all Known Sources of Energy. The Clearance Person shall communicate the transmission, distribution, or substation apparatus to be worked on. The Zone of Protection shall be adequate for the work to be performed. The Clearance can only be obtained by an Authorized Clearance Person.

2.5.2 Preparation of the Clearance by the ECC Operator

A. The ECC Operator shall check carefully to make sure that no condition exists which will prevent the switching operations for the proposed Clearance.

B. The ECC Operator shall have the section of the circuit or apparatus involved Isolated from all Known Sources of Energy by directing that the appropriate devices be placed in the Protective Position and DNO or Test Tagged.

C. Where applicable, for overhead distribution Clearances only, the Clearance Person and ECC Operator shall discuss and agree on the location of System Operator Grounds and the ECC Operator shall document and track the location of the Grounds. In addition, the Clearance Person shall document the Ground location on the Field Switching Order form. If System Operator Grounds are not utilized then Worker Grounds are to be used where required.

D. Where applicable, System Operator Grounds may be ordered on prior to or after Clearance has been issued. The Clearance Person does not have permission to work until the system has been tested De-energized and Grounds installed.

E. Where applicable, the ECC Operator shall order the circuit (apparatus) tested for the absence of system potential prior to ordering on any System Operator Grounds. An approved test shall be used to test De-energized before grounding at the point of test. The testing and grounding process shall be continuous. Grounds shall be installed and Caution Tagged immediately after testing the circuit or apparatus. A re-test shall be conducted if the grounding process is interrupted.

NOTE:
Additional System Operator Grounds may be ordered on or existing System Operator Grounds may be ordered relocated within a Zone of Protection after a Clearance has been issued provided all Clearance Persons have been notified.

For overhead distribution Clearances only, if System Operator Grounds are not utilized then Worker Grounds are to be used where required.

2.5.3 Issuing the Clearance

A Clearance shall be issued by the ECC Operator and acknowledged by the Clearance Person utilizing the proper formal language and Three Part Communication techniques. Prior to issuing a Clearance to the Clearance Person(s) the ECC Operator shall:

A. State the circuit and Switching Control Number where applicable.

B. Specify the devices establishing the Zone of Protection.

C. Issue Clearance(s) on the established Zone of Protection.

2.5.4 Responsibility of the Clearance Person(s)

A. Utilize the required testing equipment, Personal Protective Equipment and Fire Retardant clothing required for the task to be performed.

B. All equipment shall be considered energized at all times unless Isolated, proven De-energized and Grounded (if applicable).

C. Preparation for Work

1. Testing for Potential

After receiving the Clearance, an approved test shall be used to test De-energized before grounding at the point of test. The testing and grounding process shall be continuous. Worker Grounds shall be installed immediately after testing the circuit or apparatus. A re-test shall be conducted if the grounding process is interrupted.

2. Working with Grounds Applied

When working with Grounds applied, reference appropriate grounding procedures for the application of Grounds.

3. Working without Grounds

When working on Isolated and Tagged substation apparatus where minimum approach distances will be maintained, Grounds will not be required to perform work such as mechanism inspections or similar work. Added safeguards are to be included where possible.

2.5.5 Multiple Persons Working Within the Same Zone of Protection

When multiple Clearance Persons must work within the same Zone of Protection, there are two options available. Only ONE set of Tags will be used on the same Zone of Protection.

A. Option One: Working under someone else's Clearance

1. Separate crews can work under one Clearance issued to a single Clearance Person if the crews comprise a group of people working in a coordinated manner to accomplish a task on the same lines or apparatus under the direction of a single Clearance Person.

2. The ECC Operator is not notified of this arrangement.

3. The Clearance Person is responsible for the safety, testing and grounding and the work performed by all people working under their Clearance.

B. Option Two: Obtain Clearance through the ECC Operator

This option is not intended to be used to perform a Transfer of work. This process MAY NOT be used for a Zone of Protection established with Test Tags.

This option shall be followed when multiple crews work independently or jointly under the same Zone of Protection (one set of DNO Tags with multiple Clearances issued) provided the following requirements are met:

1. The existing Zone of Protection is adequate for the additional work at all times.

2. Issuance of another Clearance shall be permitted only with the knowledge and authorization of the ECC Operator. The ECC Operator shall notify all existing Clearance Persons of the additional Clearance Person(s) being added.

3. The ECC Operator shall track the names of all Clearance Person(s) under the same Zone of Protection.

4. Each Clearance Person shall Release their Clearance with the ECC Operator when their work is completed and report to the ECC Operator that all their Grounds have been removed, and that personnel and equipment are in the clear.

5. Each Clearance Person shall explain clearly to the ECC Operator all changes and/or repairs made by them.

6. While personal safety is the responsibility of each individual worker, the Clearance Person is responsible for the safety, testing and grounding and the work performed by the people under their immediate direction.

2.5.6 Releasing a Clearance

A Clearance shall be released by the Clearance Person and acknowledged by the ECC Operator utilizing the proper formal language and Three Part Communication techniques.

Prior to the Release of a Clearance, the Authorized Person(s) shall determine and report to the ECC Operator:

A. All members in the crew are clear of the lines and/or apparatus

B. All Worker Grounds, if applied, have been removed.

C. Any change(s) from the original operating position of any device within the Zone of Protection.

D. The lines or apparatus are ready to be energized.

2.5.7 Reissuing Clearance

If additional work is required after the Authorized Person has surrendered their Clearance, the ECC Operator may:

A. Issue orders to operate the necessary device(s) that will re-establish the original Zone of Protection for that apparatus or circuit.

B. Issue orders to Tag the necessary device(s) using the original Switching Control Number (where applicable) assigned to that apparatus or circuit.

C. Issue Clearance(s) on the re-established Zone of Protection.

Note: The Release of Clearance is normally conducted for the restoration of the circuit or apparatus to normal service. If testing with system voltage is required, the Clearance Person shall inform the ECC Operator of this requirement and the "Release of Clearance for Testing with System Voltages" process will be followed.

2.5.8 Release of Clearance for In-Service Testing

Testing of apparatus or circuits using primary system voltages shall be performed only under the direction of the ECC Operator.

A. No testing shall be done on apparatus or circuits until the ECC Operator has received a Release of Clearance from all persons holding the Clearance in that Zone of Protection.

B. The Clearance Person in charge of the test and the ECC Operator shall agree on which Tagged device(s) will be operated in order to facilitate the test.

C. Prior to ordering any device closed, the ECC Operator will order the Tag(s) removed from that device.

D. Once the apparatus or circuit has been energized, in-service checks may be performed as needed (*i.e.*, phase checks, three phase voltage checks, soaking transformers/circuits, etc.).

E. After the Authorized Person in charge of the testing has been satisfied of the test procedure, they shall inform the ECC Operator that all testing has been completed and the line or apparatus is ready for service.

F. The ECC Operator may return that apparatus or circuit to service, provided that no additional work is required.

G. If additional work is required after the apparatus or circuit has been energized for testing, the ECC Operator will:

1. Issue orders to operate the necessary device(s) that will re-establish the original Zone of Protection for that apparatus or circuit.

2. Issue orders to Tag the necessary device(s) using the original Switching Control Number (where applicable) assigned to that apparatus or circuit.

3. Issue Clearance(s) on the re-established Zone of Protection.

Note: When testing with system voltages the ECC Operator and the person performing the testing (*i.e.*, phasing) will discuss and incorporate the testing into the switching sequence.

2.5.9 Expanding the Zone of Protection

The Clearance Person shall determine if the Zone of Protection is adequate for the work to be performed and may request that the Zone of Protection be expanded only with approval of the ECC Operator. The ECC Operator and the Clearance Person shall document all modifications on their appropriate forms when expanding or contracting a Zone of Protection including a full job briefing for the modified Zone of Protection.

A. During the expansion of the Zone of Protection, work may continue in the original Zone of Protection.

B. The ECC Operator shall notify all Clearance Person(s) issued the Clearance that the Zone of Protection is being expanded.

C. The ECC Operator shall order the new Tag(s) placed to expand the Zone of Protection. These Tag(s) shall have the same Switching Control Number (where applicable) as the original Clearance.

D. After the Zone of Protection has been expanded, the ECC Operator shall notify all Clearance Person(s) issued the Clearance that the Zone of Protection has been expanded and communicate to all Clearance Person(s) the new Protective Points of the Clearance.

E. Once the expanded Clearance has been issued to all Clearance Person(s), the Clearance Person(s) shall release the original Tag(s) that are no longer needed for their Zone of Protection. Clearance Person(s) may then test De-energized and Ground the newly expanded Zone of Protection.

F. The ECC Operator shall direct the released Tag(s) removed and the Switch Person may close or request the ECC Operator close the device(s) only after notifying all Clearance Person(s), and confirming that the newly expanded Zone of Protection has been Grounded.

G. If additional grounding is not required by the work that is being done in the expanded Zone of Protection, the ECC Operator shall direct the released Tag(s) removed and the Switch Person may close or request the ECC Operator close the device(s) only after notifying all Clearance Person(s) and confirming that the newly expanded Zone of Protection has been tested De-energized.

H. The Clearance Person shall communicate with the ECC Operator the configuration of the circuit when the work has been completed and the Clearance is being Released.

2.5.10 Contracting (Reducing) the Zone of Protection

While establishing the new reduced Zone of Protection within the existing Zone of Protection, work may continue in any part of the original Zone of Protection with permission from the Clearance Person(s). Prior to releasing any Tags associated with the original Zone of Protection, Grounds shall be applied or relocated in the new Zone of Protection (if necessary) and all workers, equipment, and Grounds shall be in the clear of the section to be re-energized.

A. The ECC Operator shall notify all Clearance Person(s) issued the Clearance that the Zone of Protection is being contracted.

B. The ECC Operator shall order the new Tag(s) placed to contract the Zone of Protection. These Tag(s) shall have the same Switching Control Number (where applicable) as the original Clearance.

C. After the Zone of Protection has been contracted, the ECC Operator shall notify all Clearance Person(s) issued the Clearance that the Zone of Protection has been contracted and communicate to all Clearance Person(s) the new Protective Points of the Clearance.

D. Once the contracted Clearance has been issued to all Clearance Person(s), the Clearance Person(s) shall release the original Tag(s) that are no longer needed for the original Zone of Protection.

E. The ECC Operator shall then direct the released Tag(s) removed, and switching performed as needed to re-energize equipment.

2.5.11 Transferring a Clearance

Under this process the work can continue.

A. Prior to contacting the ECC Operator, both the existing and the new Clearance Person shall conduct a comprehensive job transfer brief covering the job status, the Isolated Zone of Protection and Tag locations, worker status, and Ground locations.

B. The Clearance Person contacts the ECC Operator and informs them that he has conducted the briefing with the new Clearance Person and request the Transfer of Clearance.

C. The new Clearance Person contacts the ECC Operator and requests the Clearance Protective Points by device and location and then is issued the Clearance by the ECC Operator.

D. The original Clearance Person shall surrender their Clearance with the ECC Operator.

2.6 Interconnections with Other Controlling Authorities, Utilities, Generators, or Customers

2.6.1 When Controlling Authorities, Foreign Utilities, Generators or Customers Require a Guarantee

A. A designee of the Controlling Authority, foreign utility, generator, or customer shall be issued a Guarantee by the AVANGRID Networks ECC Operator.

B. A DNO Tag shall be used to Tag all Protective Points listed on the Guarantee.

C. Where applicable, the Guarantee shall have a number issued by the AVANGRID Networks ECC Operator.

D. The AVANGRID Networks ECC Operator issuing the Guarantee shall record the name and contact number of the ECC Operator of the Controlling Authority, foreign utility, generator, or customer.

E. Grounds may be applied at the request of the foreign ECC Operator. The Controlling Authority, foreign utility, generator, or customer System Operator will be advised by the AVANGRID Networks ECC Operator that the Grounds installed are only a visible indication that the line/apparatus has been De-energized at the point of grounding, and should not be considered protection for their workers.

2.6.2 When AVANGRID Networks Requires Isolation from a Controlling Authority, Foreign Utility, Generator, or Customer

A. The AVANGRID Networks ECC Operator will accept the Controlling Authority, foreign utility, generator, or customer's Isolation practices as defined by their rules or will direct an AVANGRID Networks Switch Person to DNO Tag the required Protective Points for the Clearance. These Protective Points shall be Tagged only after a Visible Open has been created by the Controlling Authority, foreign utility, generator, or customer.

B. The AVANGRID Networks ECC Operator shall document the Protective Points as part of the Zone of Protection in the Clearance to be issued to the Clearance Person(s).

C. The AVANGRID Networks ECC Operator may request the Controlling Authority, foreign utility, generator, or customer to close mechanical Grounds as part of the Clearance.

D. The Guarantee shall not be released to the Controlling Authority, foreign utility, generator, or customer until after the AVANGRID Networks ECC Operator receives the Release of Clearance from the Clearance Person.

2.6.3 When a Controlling Authority or Foreign Utility Control Center Requires an NRA

A. A designee of the Controlling Authority or foreign utility, acting as their ECC Operator shall be issued an NRA by the AVANGRID Networks ECC Operator.

B. The NRA can be issued after the reclosing control(s) and supervisory controls for a specific circuit have been placed in the non-reclose position and the necessary NRA Tags placed.

C. Where applicable, the NRA shall have a number issued by the AVANGRID Networks ECC Operator.

D. The AVANGRID Networks ECC Operator issuing the NRA shall record the name and contact number of the ECC Operator of the Controlling Authority or foreign utility.

E. The designee of the Controlling Authority or foreign utility, acting as their ECC Operator to whom the NRA has been issued has the responsibility to inform the AVANGRID Networks ECC Operator of any conditions that may have caused the device to operate.

F. Manual reclosing shall not be performed until there is concurrence between the designee of the Controlling Authority or foreign utility, acting as their ECC Operator to whom the NRA was issued and the AVANGRID Networks ECC Operator.

G. The breaker(s) or device shall not be restored to the automatic reclose position until the NRA has been released by the designee of the Controlling Authoriy or foreign utility, acting as their ECC Operator.

2.6.4 When AVANGRID Networks Requires an NRA from a Controlling Authority or Foreign Utility Control Center

A. The AVANGRID Networks ECC Operator will accept the Controlling Authority or foreign utility's NRA practices as defined by their rules.

B. The AVANGRID Networks ECC Operator shall document the Controlling Authority or foreign utility's device(s) placed in the necessary position to secure the NRA.

C. Manual reclosing shall not be performed until there is concurrence between the Authorized Person and the AVANGRID Networks ECC Operator and until the Authorized Person with the NRA releases or surrenders their NRA.

D. The NRA shall not be released to the Controlling Authority or foreign utility ECC Operator until after the AVANGRID Networks ECC Operator receives a release of the NRA from the Authorized Person.

2.7 Delegation of Control – Controllership

When control of a portion of the network is to be delegated by the ECC Operator to an Authorized Person (for equipment or de-centralized location), the ECC Operator shall issue Controllership to the Authorized Person accepting control, documenting the specific lines, apparatus, or location included in the Controllership.

The ECC Operator shall inform the Authorized Person of any known abnormal conditions that exist on the line, apparatus, or location under their control. The Authorized Person shall assume all duties and responsibilities of the ECC Operator.

When control needs to be delegated further, notification requirements for individuals or location shall be established with the ECC Operator at the time of delegation.

The Authorized Person who has been delegated control shall notify the ECC Operator when SCADA devices within their area of control need to be operated or Tagged.

When Controllership is released, any known abnormal conditions that exist on the line, apparatus, or location shall be communicated to the ECC Operator.

2.8 Revisions to These Procedures

Revisions to these procedures will be made by the AVANGRID Networks Energy Control Center with input and review by stakeholders and users of the AVANGRID Networks Energy Control Center Switching and Tagging Rules and Procedures.

3.0 REFERENCES

- CONVEX TD800 Switching and Tagging
- UI OP-G88 Distribution Electrical Switching & Tagging Procedure

4.0 DOCUMENT RETENTION

All documentation created under this procedure will be retained pursuant to the AVANGRID Networks Document Retention Schedule or applicable regulatory requirement, whichever is longer.

Approved by: Michael R. Craven 3/29/2019
Michael R. Craven Date
Senior Director – Electric Operations

Approved by: 3/29/2019
Tom DePeter Date
Senior Director – Electric Operations

Revision History

Version	Date	Comments
0	04.01.2017	Document creation; based on United Illuminating OP-G88 (TD800) which will be replaced by common document; created to unify all operating companies under a common process
1	3.20.2019	Biennial review; minor editing for clarity; Sec 1.3.14: added "to or" to the Exception in Sec A.2, deleted "at any voltage" in D, added "to or" to the Exception in D.2, moved the underlined sentence referencing one Clearance Person from D.5 to D.9 and added a qualifier to accommodate Transfer of Clearance; Sec 2.1.1: added clarification in B.1 that others in the same Zone of Protection are to be notified, reworded B.4 to clarify that changes that remain when Clearance is released will be communicated to the ECC Operator; Sec 2.4.2: clarified in C that normally closed source devices that open are to be DNO tagged for LLP; Sec 2.5.2: added to note in E to clarify that System Operator Grounds are ordered relocated by ECC; Sec 2.5.8: replaced title System Voltages with In Service Testing to clarify re-energizing using system voltages is essentially placing something in service and is under control of ECC; changed signatory from J. Cole to T. DePeter.

Attachment 1
Definitions

Authorized Person: A person who is knowledgeable in the construction and operation of electric power generation, transmission, substation, and/or distribution apparatus specific to their job classification along with the associated hazards in specific duties pertaining to electric operations, who is further designated by a departmental manager as having been successfully trained, tested, and who demonstrates proficiency, understanding, and the skills necessary to perform duties associated with this procedure.

Exception: A person who is undergoing on-the-job training and who, in the course of such training, has demonstrated an ability to perform duties safely at his or her level of training and who is under the direct supervision of an Authorized Person is considered to be an Authorized Person in the performance of those duties. Note: Trainees who perform switching under this exception shall not be issued Clearances, Non-Reclose Assurances, or Live Line Permissions.

Authorized Person List: A formal document developed and maintained by AVANGRID Networks Control Center management listing all individuals designated as an Authorized Person.

Authorized Clearance Person: A person designated by a departmental manager, or their designee, who has successfully been tested and has demonstrated proficiency and understanding of the AVANGRID Networks Energy Control Center Switching and Tagging Rules and Procedures, who is authorized to receive Clearance and perform work within a specified Zone of Clearance, but is NOT authorized to perform switching and/or grounding.

Authorized Switch Person: An Authorized Person that is knowledgeable in the operation of electrical apparatus for the purpose of switching and Tagging of electrical circuits or apparatus. A worker who does not hold Authorized Person qualification may switch under the direct supervision of an Authorized Switch Person.

Clearance (for work): Authorization to an Authorized Person to perform specified work within a Zone of Protection. Work may only begin on a line, circuit or piece of equipment after it has been made safe by removal from service, De-energizing, Tagging, testing, and grounding (where applicable), all in accordance with these Procedures. A Clearance may only be issued by the ECC Operator unless Controllership has been delegated.

Controllership: The transfer of operating jurisdiction of a specific part (equipment or location) of the electrical system from the ECC Operator to an Authorized Person or Controlling Authority for reasons related to restoration of electrical service, communications problems, or workload.

Controlling Authority: The authority or department with jurisdiction over specifically-defined regions, voltage classes, or otherwise designated portions of the AVANGRID Networks Electric System, or the representative of an adjacent generator, utility, region, or customer.

Dead: Isolated, Tagged, tested De-energized and Grounded.

De-energized: The absence of normal operating voltages associated with the operation of the system or control circuits. Under this condition, work can only be performed using Live Line Work Methods.

Demarcation Line or Demarcation Point (DL or DP): A disconnecting device or mutually-agreed upon place (load side of a breaker, pole, etc.) where ownership or authority changes between the AVANGRID Networks Electric System and an interconnected utility, customer facility, Controlling Authority, or generator. This line or point shall be controlled by the Controlling Authority who directs switching.

Energy Control Center (ECC): This organization is the Controlling Authority for the portion of the electric system assigned to it and orders and coordinates any switching orders necessary to ensure operations are as safe and effective as possible.

Energy Control Center (ECC) Operator: An Authorized Person who directs, controls, monitors, and operates the portion of the electric system and its associated apparatus for which they are the Controlling Authority.

Energy Management System (EMS): The ECC computer system which has the SCADA inputs and ability to exercise control over field devices.

Ground, Grounded: Intentionally connected to earth through a metallic ground connection.

Grounds: There are two types of grounds referred to in this procedure:

- **System Operator Grounds –** Grounds whose installation, removal or operation is directed by the ECC Operator.
- **Worker Grounds –** Grounds whose installation or removal is directed by the Clearance Person.

Guarantee, Station Guarantee, etc.: A Guarantee is a formal statement given to an inter-connected Controlling Authority, foreign utility, generator or customer that requested device(s) are placed in the requested position and appropriately Tagged and will remain so until the Guarantee is released by the recipient.

Higher Authority: An Authorized Person at the same or higher level of Management above the Authorized Person who is holding the Clearance, NRA, or LLP and is knowledgeable in the work to be performed.

Hot Line Tag: A function of some devices that disables the time-overcurrent protection curve in the device and results in an instantaneous trip with no reclosing when faults are sensed. This is used in addition to NRA when requested by Authorized Persons who will be working on energized lines.

Isolate, Isolated, Isolation: Disconnected from all Known Sources of Energy by open switches, disconnectors, jumpers, taps, or other means and absent of nominal voltages.

Known Source of Energy: One side of an energized primary voltage switch or device in the open position, which if placed in the closed position, would energize into the work zone. In AVANGRID Networks this includes current and potential transformers where the high side is connected to the primary voltage system. Also, a generator identified on a primary circuit print, is a Known Source of Energy.

Limits: See Protective Points.

Live Line Permission (LLP): A formal statement from the ECC Operator to an Authorized Person to perform work on a De-energized line or equipment utilizing Live Line Work Methods.

Live Line Work Methods: Work performed utilizing company approved insulate and Isolate practices (*e.g.,* hotstick or rubber gloving).

Non-Reclose Assurance (NRA): A formal statement from the ECC Operator to an Authorized Person to perform work on, or near, designated energized lines or apparatus after all associated reclosing devices, are disabled and Tagged. This may include enabling fast trip settings for arc flash protection (Hot Line Tag).

Protective Points: Devices providing Visible Openings that define a Zone of Protection.

Protective Position: The Tagged position of a mechanical or electrical device with a Visible Opening that prohibits the energizing or the re-energization of a specific work area. *Exceptions* to a Visible Opening: Individual operating companies may specify devices approved for this application due to physical limitations.

Radial Side Taps: The point on a single or multi-phase circuit beyond which there is no tie point toward the load side of the circuit.

Re-Issue: The issuance of a previously released Clearance or NRA from the ECC Operator to a Clearance Person or Authorized Person.

Release of Clearance: The act in which a Clearance Person(s) reports to the ECC Operator that their Worker Grounds have been removed (if applicable), all workers and equipment are in the clear, and the status or condition of the line or apparatus they were working on.

Switching Control Number: A a unique number assigned by the ECC Operator for the purposes of tracking a LLP, NRA, Clearance, Guarantee or other switching sequence.

System Operator: See ECC Operator.

System Operator Grounds: See Grounds.

Tag, Tagged, Tagging: Tag in any tense refers to the physical or electronic placement of an indicator that is recognized by appropriately trained individuals to indicate the apparatus on which the Tag is placed may not be operated until the person or persons having authority and responsibility for the Tag surrenders their authority, or "clears" from the Tag.

Three Part Communication: Verbal communications that require accurate read back with a final acknowledgement by the originator. Communications shall be conducted in a clear, concise and definitive manner. The recipient is required to read back the information correctly. This response shall be acknowledged as correct by the originator or the original statement repeated to resolve any misunderstandings.

Transfer: A process to re-assign a Clearance, NRA, or LLP from one Authorized Person to another through the ECC Operator.

Visible Opening: A visible physical break in a circuit that can be supplied by an open disconnect, tap, link, etc. and can be visually verified to be open. This includes an opening that is understood to be equal to a Visible Opening but may only be observable through a viewport or via camera. This can be Gas Insulated Switchgear or any other modern installation that is not in the open air.

Note: Oil Fused Cutouts, Vacuum switches, network protectors, network Transformer Oil Disconnects, and other devices are approved for this application.

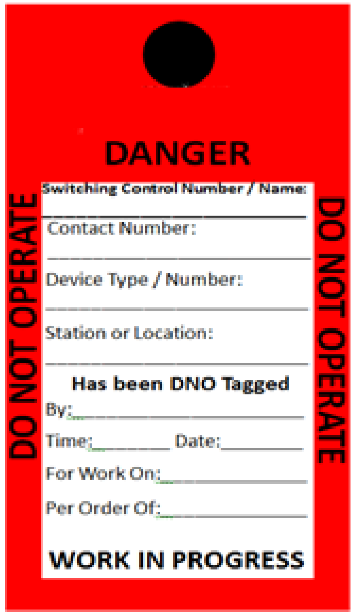
Voltage Testing: Testing when applied voltages result in voltages greater than 50 volts. This includes but is not limited to Fault Finder, Power Factor, Insulation Resistance measurements, TTR, Hi-Pot, or System Voltages, etc. Appropriate minimum approach distances shall be maintained within the area under test.

Zone of Protection: An area defined by Visible Opening points that Isolate all Known Sources of Energy. This area is created by Isolating, De-energizing and Tagging every protective point of Isolation from external sources of primary or nominal-voltage energy that could create a hazard for workers.

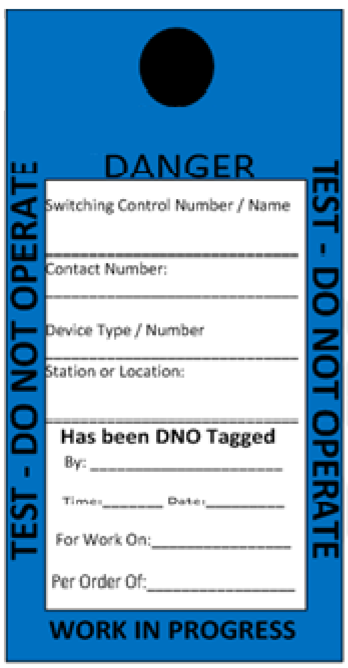
Attachment 2
Approved Tags

Front Back

DNO Tag



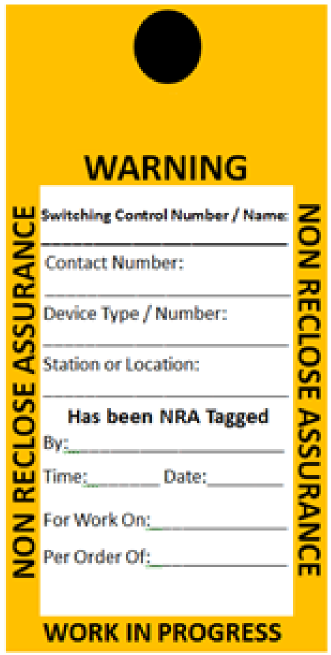
Test Tag

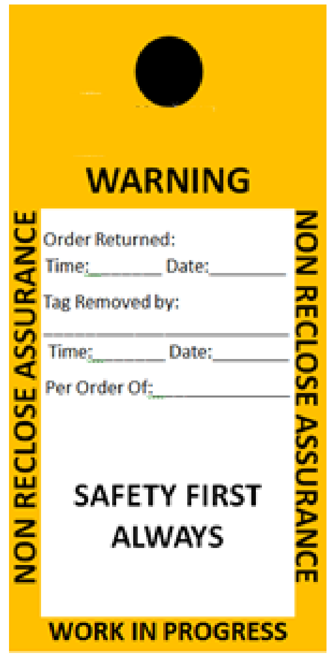


Attachment 2
Approved Tags

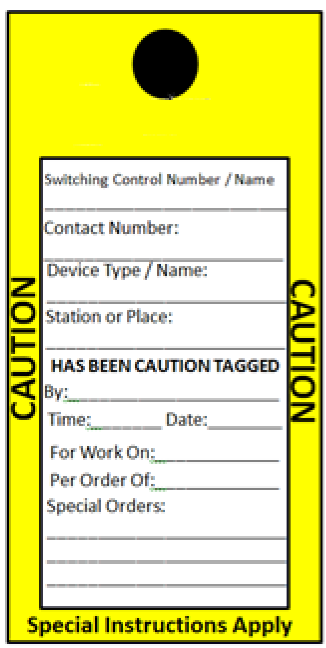
Front | Back

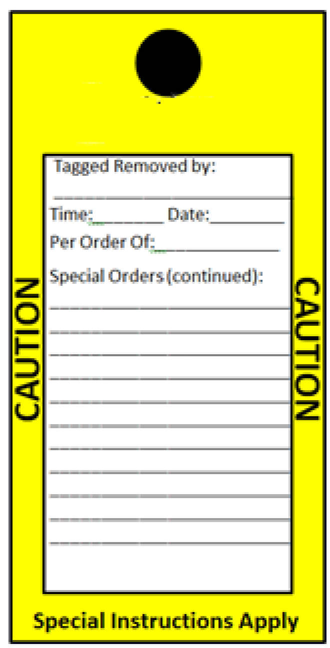
Non-Reclose Assurance Tag





Caution Tag





Attachment 3
Approved Forms

FRONT

FIELD SWITCHING ORDER Page ____ of _____

REASON FOR SWITCHING____

SYSTEM OPERATOR _______________ ORDER # __________ SWITCH PERSON _____________

DATE: _____________ CIRCUIT / SWITCHING LOCATION(s) ___________________________

☐ CLEARANCE – GROUNDED – DNO / MWT / TEST
☐ PRE SWITCH BRIEF COMPLETE
☐ LIVE LINE PERMISSION –DNO
☐ REQUIRED PPE
☐ NRA
☐ VERIFY PRINT AND REVISION
☐ GROUNDS LOCATION REVIEWED BY SYSTEM OPERATOR AND CLEARANCE HOLDER

ISSUED TIME____________ RELEASED TIME ___________

FIELD SWITCHING ORDER					
STEP	LOCATION	SWITCHING DESCRIPTION	TAG	TIME ISSUED	TIME EXECUTED
RETURN ALL TAGS AND ORDERS TO SUPERVISION FOR REVIEW					

Attachment 3
Approved Forms
BACK

FIELD SWITCHING ORDER

Page ____ of ____

STEP	LOCATION	SWITCHING DESCRIPTION	TAG	TIME ISSUED	TIME EXECUTED
RETURN ALL TAGS AND ORDERS TO SUPERVISION FOR REVIEW					