BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2299

In the Matter of Application of Portland General Electric Company, PacifiCorp dba Pacific Power, and Idaho Power Company for Approval of Proposed Schedules and Standard Power Purchase Agreement for Qualifying Facilities up to 10 MW.	**JOINT UTILITIES' APPLICATION**

I. INTRODUCTION

In accordance with Order No. 23-152 issued on April 25, 2023 and Order No. 23-214 issued on June 20, 2023, by the Public Utility Commission of Oregon (Commission) in docket AR 631, Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (Idaho Power) (together, the Joint Utilities) respectfully seek approval of: (1) the Joint Utilities' proposed standard power purchase agreement (PPA) for qualifying facilities (QF) of 10 megawatts (MW) or less; (2) PGE's revised Schedule 201; (3) PacifiCorp's revised Oregon Standard Avoided Cost Rates – Avoided Cost Purchases from Eligible Qualifying Facilities Schedule (hereinafter, Oregon Standard QF Schedule); and (4) Idaho Power's revised Schedule 85.

In Order Nos. 23-152 and 23-214, the Commission adopted new rules and amended existing rules in Chapter 860, Division 029 ("New Rules") in furtherance of its goals to: (i) modernize procedures, terms, and conditions associated with standard contracts for QFs under the Public Utilities Regulatory Policies Act of 1978 (PURPA); (ii) standardize contract terms among the Joint Utilities[1]; and (iii) promote the economically efficient development of QFs while ensuring customers are indifferent to and no worse off because of the purchase of QF power.[2] The Joint Utilities submit the attached documents in compliance with Order Nos. 23-152 and 23-214 to further advance the Commission's goals.

The Joint Utilities propose one standard PPA that is drafted to conform to Oregon law and the Commission's orders and policies. The proposed standard PPA will be used by all three utilities and will address new and existing resources, variable and non-variable resources, renewable and non-renewable resources, and on-system and off-system resources. The standard PPA will increase efficiency and reduce the likelihood of future disputes among parties by using consistent contracting practices and language and advancing a common understanding of the agreement's terms and conditions. In fact, the proposed standard PPA will replace ***a total of 16 contracts***, including PGE's eight Schedule 201 standard contracts,[3] PacifiCorp's four standard contracts for firm delivery from eligible Oregon QFs,[4] and Idaho Power's four Schedule 85 standard contracts.[5] Similarly, the Joint Utilities revised their schedules to comply with the rules adopted by the Commission in Order Nos. 23-152 and 23-214, and removed redundant provisions (provisions

---

[1] *See In re Public Utility Commission of Oregon, Request to Adopt Scope and Process for the Investigation Into PURPA Implementation*, Docket UM 2000, Order No. 19-254 at 1, App. A at 4 (July 31, 2019) (adopting the finding of Staff that development of "more standardized contracts across utilities could be beneficial").

[2] *See, e.g.*, *In re Public Utility Commission of Oregon, Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at 1 (May 13, 2005) ("This Commission's goal has been to encourage the economically efficient development of these qualifying facilities (QFs), while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power.").

[3] *See Interconnection Resource Library*, Portland General Electric Company, https://portlandgeneral.com/renewable-installers/interconnection-resource-library (last visited July 24, 2023).

[4] *See PURPA Power Source Agreement*, *Oregon Rates and Tariffs*, Pacific Power, https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html (last visited July 24, 2023).

[5] *See Oregon Special Agreements*, Idaho Power Company, https://www.idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/ (last visited July 24, 2023).

that cover the same topic and that previously were included in both the schedule and standard PPA) to streamline and clarify the schedules.

Because the Joint Utilities' proposed standard PPA and revised schedules comply with the New Rules and are consistent and streamlined, the Joint Utilities respectfully request that the Commission approve the enclosed filings.

The Joint Utilities request the Commission make the standard PPA and revised schedules effective 30 days after this filing on an interim basis so that the Joint Utilities have Commission-approved and rule-compliant standard PPA and schedules in place during the compliance-filing review process.[6] Review and approval of this compliance filing will take time, but once the new rules are effective, the Joint Utilities' existing standard contracts—which were approved based on Commission policy direction and original compliance forms from nearly 20 years ago—will be non-compliant with the New Rules, in addition to already being outdated and not consistent with current practices and standards. The Joint Utilities' request for interim effectiveness is consistent with the Commission's approach when the Commission first required standard PPAs in docket UM 1129 and will ensure that standard contracting can continue without interruption during the pendency of the compliance filing review process.[7] This interim relief is particularly critical as the Commission will soon adopt new standard avoided cost pricing for solar-plus-storage resources, which may result in increased requests for standard contracts. Solar-plus-storage resources, and all eligible QFs, must have access to a rule-compliant standard PPA while the utilities' compliance filing is reviewed.

As of the date of the Joint Utilities' Application, PacifiCorp has received requests for

---

[6] The Joint Utilities' recommendation for interim effectiveness assumes that the New Rules are filed with the Secretary of State and therefore effective prior to the 30-day period after which the standard PPA would become effective on an interim basis.
[7] Docket UM 1129, Order No. 05-899 at 2-3 (Aug. 9, 2005).

standard PPAs from three QFs with which it has not yet executed contracts. PacifiCorp requests the Commission allow these QFs be "grandfathered" in under the existing rules and be entitled to the current Commission-approved standard PPAs, so long as these PPAs are executed within 90 days after the New Rules take effect.[8] Approval of this request will provide needed clarity and may prevent the filing of unnecessary Commission complaints.

II. STANDARD POWER PURCHASE AGREEMENT

To comply with the New Rules and "create a settled and uniform institutional climate" for Oregon QFs,[9] the Joint Utilities propose a uniform standard PPA that will be used by all three utilities and apply to all QF types. This proposed standard PPA complies with the New Rules adopted in Order Nos. 23-152 and 23-214 and is vastly superior to the status quo because it standardizes and streamlines standard PPA contracting and incorporates current industry standard contracting norms.

A. The Proposed Standard PPA Complies with Order Nos. 23-152 and 23-214.

The Joint Utilities drafted the standard PPA first and foremost to comply with the New Rules, which reflect the Commission's most recent policy determinations and balancing of interests. To enable efficient review of the standard PPA, the Joint Utilities have included Attachment A to this Application, which details where in the standard PPA each of the New Rules has been addressed.

B. The Proposed Standard PPA is Vastly Superior to the Utilities' Current, Outdated Standard Contracts as It is Streamlined and Reflects Current PPA Contracting Norms.

Because the extensive scope of the New Rules required the Joint Utilities to completely

[8] To the extent necessary to effectuate the grandfathering, PacifiCorp requests that the Commission waive the requirements of the New Rules under current OAR 860-029-0005(4) [New Rule OAR 860-029-0005(3)].
[9] ORS 758.515(3)(b).

overhaul their current PPA forms, the Joint Utilities took the opportunity to develop a comprehensive standard PPA contract that (1) creates efficiencies by consolidating multiple standard agreement forms into one document, and (2) reflects current industry standard contracting practices.

1. The Proposed Standard PPA Streamlines Standard PPA Contracting in Oregon.

The proposed standard PPA will streamline and simplify PPA contracting in Oregon. As indicated above, the proposed standard PPA applies to new and existing resources, variable and non-variable resources, renewable and non-renewable resources, and on-system and off-system resources. Indeed, the proposed standard PPA will replace ***a total of 16 contracts***—PGE's eight standard contracts,[10] PacifiCorp's four standard contracts,[11] and Idaho Power's four standard contracts.[12] The use of a uniform standard PPA will facilitate a common understanding of the agreement's terms and conditions, thereby reducing the likelihood of future disputes.

Although one standard PPA for all QF types for all Joint Utilities will be inherently longer than any one of the utilities' current standard contracts, a one-stop-shop standard PPA for all three utilities and all types of QFs offers significant efficiencies for QF developers and utilities alike. As an example, while PacifiCorp's existing standard contracts are indeed relatively shorter than the Joint Utilities' proposed uniform standard PPA, they are not in and of themselves short with respect to page length. PacifiCorp's PPA for firm off-system QFs is a total of 44 pages alone (30

---

[10] *See Interconnection Resource Library*, Portland General Electric Company, https://portlandgeneral.com/renewable-installers/interconnection-resource-library (last visited July 24, 2023).
[11] *See PURPA Power Source Agreement*, *Oregon Rates and Tariffs*, Pacific Power, https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html (last visited July 24, 2023).
[12] *See Oregon Special Agreements*, Idaho Power Company, https://www.idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/ (last visited July 24, 2023).

pages plus 14 pages of exhibits).[13] PacifiCorp's other three standard contracts range from a total of 36 to 39 pages.[14] Together, PacifiCorp's four current standard contracts for firm delivery have a combined total page length of 158 pages. In comparison, the Joint Utilities' proposed uniform standard PPA—which addresses all resource types, replaces the utilities' 16 current standard contracts, and adds additional terms and conditions to comply with the New Rules and reflect industry standard contracting practices—is a total of 75 pages (55 pages plus 20 pages of exhibits).

Moreover, the Joint Utilities' proposal for a single, standard PPA is more efficient than simply redlining their existing Oregon agreements because any redlines to bring existing contracts into compliance with the New Rules—which are numerous, complex, and touch on many different elements of the standard PPA—would be extensive to the point that the redlines would be of little use. Given that the scope of the New Rules required the Joint Utilities to effectively redraft the existing PPAs, the Joint Utilities resolved to minimize the workload in this docket and simplify standard PPA contracting by creating a single agreement for all three utilities and all resource types rather than replace each of the 16 existing agreements with new forms of agreement.

The length, scope, and detail of the proposed uniform standard PPA is warranted not just because of the complexity of the New Rules, the inclusion of industry standard contracting provisions, and the fact that it replaces 16 existing agreements, but also because: (i) the nominal value of each of these standard contracts is in the millions of dollars; (ii) standard contracts are long-term agreements that must be durable over a 20-year period; (iii) the nature of the business

---

[13] PacifiCorp's Power Purchase Agreement for Firm Qualifying Facility (New or Existing) Located in Non-PacifiCorp Control Area, Interconnecting to Non-PacifiCorp System, with 10,000 kW Facility Capacity Rating, or Less, and Uninterruptible Transmission to the Point of Delivery, *available at* https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_Firm_Off_System_QF.pdf (last visited July 24, 2023).

[14] *See PURPA Power Source Agreement*, *Oregon Rates and Tariffs*, Pacific Power, https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html (last visited July 24, 2023).

of buying and selling power is complex; and (iv) there is a need for comprehensive provisions regarding the parties' respective rights and obligations in order to reduce the likelihood of disputes.

2. The Proposed Standard PPA Reflects Current PPA Contracting Norms.

The Joint Utilities' existing standard contracts are based on forms that were adopted in docket UM 1129 in 2005, and therefore reflect industry standards and practices that were prevalent nearly 20 years ago.[15] Since that time, the Joint Utilities, and the utility industry as a whole, have made great strides to modernize and improve contracting practices and provisions, particularly in response to increased contracting for intermittent renewable generation. However, the Joint Utilities' existing standard PPA contracts have not been updated to reflect these improvements. Moreover, vague and ambiguous provisions in the existing standard contracts have led to a significant number of contractual disputes in recent years. The fact that each utility has different standard contracts with a different contractual structure and different wording has further fueled these disputes over contract interpretation. The different utility-specific contracts have also caused confusion and posed challenges for developers, who must navigate three different utility form agreements when deciding whether to contract in Oregon. The Joint Utilities intend for the proposed, uniform standard PPA to remedy some of these challenges.

The proposed standard PPA implements current industry contracting standards and practices by leveraging language in PacifiCorp's Washington Standard PPA ("PAC WA Standard PPA"),[16] which reflects input from the Northwest & Intermountain Power Producers Coalition (NIPPC) and the Renewable Energy Coalition (REC), and which the Washington Utilities and

---

[15] Order No. 05-899 at 3.

[16] *In re Pacific Power & Light Company, Schedule QF Tariff Revision*, WUTC Docket UE 190666, Standard Power Purchase Agreement on behalf of Pacific Power & Light Company, Attach. A (New Small Power Production Facility) & Attach. B (Existing/Renewal Small Power Production Facility) (effective Mar. 12, 2021) (filed Mar. 1, 2021), *available at* https://www.utc.wa.gov/casedocket/2019/190666/docsets.

Transportation Commission (WUTC) allowed to go into effect on March 11, 2021.[17] Although NIPPC and REC have asked that the Joint Utilities do not represent that NIPPC and REC supported or agreed to the PAC WA Standard PPA, NIPPC and REC nevertheless are familiar with the terms of the agreement, provided comments that were incorporated into the agreement, and did not object to the agreement when it was presented to the WUTC. The PAC WA Standard PPA is the most recent commission-approved standard contract in the Pacific Northwest and has been in effect for more than two years. The framework and provisions of the PAC WA Standard PPA that have been incorporated into the proposed standard PPA were chosen in order to ensure that the proposed standard PPA is clear, comprehensive, and aligned with current industry standards and practices, consistent with Staff's acknowledgement that the PAC WA Standard PPA represents a "good starting point for discussion regarding [new] contracting terms in Oregon."[18]

III. PROPOSED SCHEDULES

A. PGE

PGE's Schedule 201 provides information about eligibility for standard avoided costs and standard PPAs and explains the standard contracting process and contract terms. In this filing, PGE revises Schedule 201 consistent with the New Rules adopted in Order Nos. 23-152 and 23-214. For example, PGE updates the process and timelines for entering into a standard PPA consistent with OAR 860-029-0046. PGE also revises certain sections to reflect the revised rules—such as the "Power Purchase Information" section, which now allows the Seller to select a scheduled commercial operation more than three years, but no more than five years, from the

[17] WUTC Docket UE 190666, Standard Power Purchase Agreement on behalf of Pacific Power & Light Company, Cover Letter at 1 (Mar. 1, 2021), *available at* https://www.utc.wa.gov/casedocket/2019/190666/docsets.
[18] *See In re Rulemaking to Address Procedures, Terms, and Conditions Associated with Qualifying Facilities (QF) Standard Contracts*, Docket AR 631, Updated Staff Proposal at 1 (Apr. 29, 2021).

effective date without reducing the fixed-price term if the Seller provides a PGE interconnection study to PGE showing that it will take PGE longer than three years from the effective date of the PPA to complete the required interconnection consistent with OAR 860-029-0120(5)(b). Finally, PGE reorganizes Schedule 201 and eliminates repetition to streamline the document and prevent confusion. As with PGE's standard contract, Schedule 201 is a product of many years of incremental edits and has not undergone a comprehensive revision since it was first approved in 2005.[19]

B. PacifiCorp

PacifiCorp's Oregon Standard QF Schedule is available to eligible QFs of 10 MW or less making sales of electricity to PacifiCorp in Oregon. In this filing, PacifiCorp revises the Schedule to be consistent with the New Rules. In particular, PacifiCorp updates the "Definitions" section to be consistent with the definitions in OAR 860-029-0010; amends the "Process for Completing a Power Purchase Agreement" to comply with the process and timelines for entering into a standard PPA prescribed in OAR 860-029-0046; and updates the "Process for Completing a Power Purchase Agreement" and "Pricing Options" sections to allow the Seller to select a scheduled commercial operation more than three years, but no more than five years, from the effective date without reducing the fixed-price term if the Seller provides a PacifiCorp interconnection study to PacifiCorp showing that it will take longer than three years to interconnect consistent with OAR 860-029-0120(5)(b). PacifiCorp also reorganizes its Oregon Standard QF Schedule and eliminates repetition to streamline the document and prevent confusion.

C. Idaho Power

Idaho Power's Schedule 85 provides information regarding standard and negotiated,

[19] Order No. 05-899 at 3.

non-standard PPAs for QFs making sales of electricity to Idaho Power in Oregon, and describes standard pricing for eligible QFs with a nameplate capacity rating of 10 MW or less. Idaho Power revises Schedule 85 to be consistent with the New Rules adopted in Order Nos. 23-152 and 23- 214. Specifically, Idaho Power primarily amends the "Definitions" section and subsequent terminology to be consistent with the definitions in OAR 860-029-0010 and updates the "Qualifying Facility Information Inquiry Process" section to comply with the process and timelines for entering into a standard PPA prescribed in OAR 860-029-0046.

IV. INTERIM EFFECTIVE DATE

Because the utilities' compliance filing will require thorough review, the Joint Utilities anticipate that Commission approval could take several months. In the interim between the Joint Utilities' filing and the Commission's approval, the Joint Utilities will be left in a bind; the utilities will be required to offer Commission-approved standard contracts, but will be left with approved standard contracts that ***are not in compliance with*** Order Nos. 23-152 and 23-214 and the New Rules. During this period, the Joint Utilities will not be able to enter into new standard PPAs without an interim solution in place to bridge this gap until the new standard contracts are approved. For these reasons, and because the enclosed filings are "far superior to existing [schedules] and contracts,"[20] the Joint Utilities request that the Commission take a similar approach to that used in docket UM 1129 and allow the enclosed filings to take effect 30 days after this filing on an interim basis until the Commission approves final schedules and the standard PPA.

In docket UM 1129, where the Commission issued Order No. 05-584 directing the Joint Utilities to file standard contract forms and revised schedules to implement the Commission's decision,[21] the Commission allowed the utilities' standard contracts and schedules to go into effect

[20] Docket UM 1129, Order No. 05-1061 at 1 (Oct. 4, 2005) (internal quotation marks excluded).
[21] Order No. 05-584 at 59.

on an interim basis pending the Commission's investigation and final approval of the filings.[22] The Commission found that while "there [was] continued widespread interest of other parties in these issues," thereby requiring an investigation, "the filings generally implement[ed] the Commission's decision in Order No. 05-584," and therefore allowing the filings to go into interim effect was appropriate.[23] Similar circumstances in this case also warrant the Commission approving the enclosed filings on an interim basis.

The Joint Utilities would not oppose allowing QFs who execute PPAs during the interim effective period to enter an amended and restated version of their standard contract that reflects the final form of contract approved by the Commission after completing the investigation.[24] This proposal allows QFs to enter into new standard PPAs during the Commission's investigation, while ensuring that those PPAs comply with the effective rules.

In addition, to eliminate confusion during the transition to the New Rules with respect to pending standard PPAs, PacifiCorp requests that the Commission grandfather under the prior rules three specific QFs actively engaged in negotiations with PacifiCorp as of the date of this filing. To avoid confusion and potential disputes, PacifiCorp does not object to these three QFs executing current Commission-approved standard PPAs—but only if the PPAs are executed within 90 days after the New Rules take effect.[25]

V. CONTACT INFORMATION

All notices and communications with respect to this application should be addressed to:

---

[22] Order No. 05-899 at 1, 3.
[23] Order No. 05-899 at 2.
[24] Order No. 05-899 at 2 (approving including a provision in the interim standard contract that states that "the QF selling power to the Company pursuant to a QF agreement entered into during the investigation may amend the agreement to adopt revisions approved by the Commission").
[25] To the extent necessary to effectuate this request, PacifiCorp requests that the Commission waive the requirements of the New Rules under current OAR 860-029-0005(4) [New Rule OAR 860-029-0005(3)].

A. PGE

Portland General Electric Company
121 SW Salmon St., 1WTC0306
Portland, OR 97204
pge.opuc.filings@pgn.com

B. PacifiCorp

Pacific Power dba PacifiCorp
825 NE Multnomah St., Ste. 2000
Portland, OR 97232
oregondockets@pacificorp.com

C. Idaho Power

Idaho Power Company
PO Box 70
Boise, ID 83707-0070
dockets@idahopower.com

VI. CONCLUSION

For the reasons set forth above, the Joint Utilities respectfully request the Commission issue an order approving the utilities' revised schedules and standard contract on an interim basis and allowing the documents to go into interim effect 30 days after this filing, and following a comprehensive review, approve this compliance filing on a permanent basis.

/////

/////

/////

/////

/////

Respectfully submitted this 24th day of July 2023.

McDOWELL RACKNER GIBSON PC

Lisa Rackner
Adam Lowney
Jordan Schoonover
Lynne Dzubow
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
dockets@mrg-law.com

David White
Portland General Electric Company

Carla Scarsella
PacifiCorp, dba Pacific Power

Donovan Walker
Idaho Power Company

Attorneys for Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power Company

ATTACHMENT A

to

Joint Utilities' Application

Attachment A

Standard Contract Compliance with Order Nos. 23-152 and 23-214

Chapter 860, Division 029 Rules Adopted in Order No. 23-152	Standard Contract Section and Pages
OAR 860-029-0010 (Definitions for Division 029 Rules)	Section 1 (Definitions, Rules of Interpretation), Pages 2-13.
OAR 860-029-0044 (Allocation of Costs to Related to Deliveries from Off-system Qualifying Facilities)	Section 4.2 (Designation as Network Resource), Pages 20-21.
OAR 860-029-0120(4), (5) (Standard Power Purchase Agreements –Purchase Period/Fixed Price Term, Scheduled Commercial Operation Date)	Definition of "Fixed Price Period", Page 7; Definition of "Fixed Price Period End Date", Page 7; Definition of "Fixed Price Period Start Date", Page 7; Definition of "Scheduled Commercial Operation Date", Pages 11-12.
OAR 860-029-0120(6) (Standard Power Purchase Agreements – Modification of Scheduled Commercial Operation Date or Termination)	Section 2.9 (Option to Extend Scheduled Commercial Operation Date or Terminate Agreement), Page 17.
OAR 860-029-0120(7) (Standard Power Purchase Agreements – Failure to Meet Scheduled Commercial Operation Date; Damages)	Section 2.4 (Delay Damages; Schedule Recovery Plan), Pages 15-16; Section 2.5 (Damages Calculation), Page 16; Section 11.1.2(b) (Defaults by Seller – Failure to Achieve Commercial Operation), Pages 36-37.
OAR 860-029-0120(8) (Standard Power Purchase Agreements – Cure Period for Failure to Meet Scheduled Commercial Operation Date and Ability to Terminate)	Definition of "Cure Period Deadline", Page 5; Definition of "Schedule Recovery Plan", Page 11; Section 2.4 (Delay Damages; Schedule Recovery Plan), Pages 15-16.
OAR 860-029-0120(10)-(11) (Standard Power Purchase Agreements – Mechanical Availability Guarantee (MAG); Failure to Meet MAG)	Section 6.15 (Performance Guarantee), Pages 31-32; Section 11.1.2(g) (Defaults by Seller – Failure to Satisfy Performance Guarantee), Page 37; Section 11.2.4 (Remedy for Seller's Failure to Satisfy Performance Guarantee), Page 38; Exhibit F (Mechanical Availability Guarantee – Wind, Solar and Hydro Resources), Pages 55-57.
OAR 860-029-0120(12)-(13) (Standard Power Purchase Agreements – Minimum Delivery Guarantee (MDG); Failure to Meet MDG)	Section 6.15 (Performance Guarantee), Pages 31-32; Section 11.1.2(g) (Defaults by Seller – Failure to Satisfy Performance Guarantee), Page 37; Section 11.2.4 (Remedy for Seller's Failure to Satisfy Performance Guarantee), Page 38; Exhibit F (Minimum Delivery Guarantee – Geothermal, Biomass and Other Baseload Renewable Resources), Pages 58-59.

OAR 860-029-0120(14) (Standard Power Purchase Agreements – Incremental Facility Upgrades)	Section 6.1 (As-Built Supplement; Modifications to Facility), Page 24; Section 6.8 (Increase in Nameplate Capacity Rating; Expansion or New Project; Allowable Facility Upgrades), Pages 28-29; Exhibit A (Expected Monthly Net Output), Page 50; Exhibit B (Description of Seller's Facility), Page 51.
OAR 860-029-0120(15) (Standard Power Purchase Agreements – Project Development Security)	Definition of "Project Development Security", Page 10; Section 8 (Security), Pages 32-34; Section 8.2 (Project Development Security), Pages 32-33.
OAR 860-029-0120(16) (Standard Power Purchase Agreements – Default Security)	Definition of "Default Security", Page 5; Section 8 (Security), Pages 32-34; Section 8.3 (Default Security), Page 33.
OAR 860-029-0120(17) (Standard Power Purchase Agreements – Insurance Requirements)	Section 13 (Insurance), Page 42; Exhibit H (Required Insurance), Pages 61-62.
OAR 860-029-0120(18) (Standard Power Purchase Agreements – Creditworthiness Requirements)	Definition of "Credit Requirements", Pages 4-5; Section 20 (Successors and Assigns), Pages 45-46.
OAR 860-029-0120(19) (Standard Power Purchase Agreements – Information Regarding Eligibility)	Section 7 (Qualifying Facility Status; Eligibility for Standard Pricing), Page 32.
OAR 860-029-0121(3) (Delivery and Purchase under Standard Power Purchase Agreement – Obligation to Pay for Surplus Delivery of Energy)	Section 5.1 (Contract Price; Includes Capacity Rights), Page 23; Section 6.8.2 (Expansion or New Project), Page 28.
OAR 860-029-0121(4) (Delivery and Purchase under Standard Power Purchase Agreement – Title to Renewable Energy Certificates)	Section 4.7 (Ownership of Environmental Attributes; RPS Certification), Page 22.
OAR 860-029-0121(5) (Delivery and Purchase under Standard Power Purchase Agreement – Early Commencement of Commercial Operation)	Definition of "Commercial Operation Date", Page 4; Section 5.1.2 (Commercial Operation), Page 23; Exhibit J (Schedule XX and Pricing Summary Table), Page 64.
OAR 860-029-0121(6) (Delivery and Purchase under Standard Power Purchase Agreement – Test Energy)	Section 5.1.1 (Deliveries Prior to the Commercial Operation Date), Page 23; Section 10.2 (Offsets), Page 35.
OAR 860-029-0123(1)-(2) (Default, Damages, and Termination – Events of Default by Parties)	Section 11.1 (Defaults), Page 36; Section 11.1.1 (Defaults by Either Party), Page 36; Section 11.1.2 (Defaults by Seller), Pages 36-38; Section 11.1.3 (Utility Failure to Purchase), Page 38.
OAR 860-029-0123(4)(a) (Cure Period – Failure to Meet Scheduled Commercial Operation Date)	Definition of "Cure Period Deadline", Page 5; Definition of "Schedule Recovery Plan", Page 11; Section 11.1.2(b) (Defaults by Seller –

	Failure to Achieve Commercial Operation), Pages 36-37.
OAR 860-029-0123(4)(b) (Cure Period – Events of Default)	Section 11.1 (Defaults), Page 36; Section 11.1.1 (Defaults by Either Party), Page 36; Section 11.1.2 (Defaults by Seller), Pages 36-38; Section 11.1.3 (Utility Failure to Purchase), Page 38.
OAR 860-029-0123(5) (Damages)	Section 11.2 (Remedies for Events of Default), Page 38.
OAR 860-029-0123(8) (Termination of Duty to Buy)	Section 11.4 (Termination of Duty to Buy), Page 39.
OAR 860-029-0123(9) (Termination Damages)	Section 11.5 (Termination Damages), Pages 39-40.
OAR 860-029-0123(10) (Duty/Right to Mitigate)	Section 11.6 (Duty/Right to Mitigate), Page 40.
OAR 860-029-0123(11) (Security)	Section 11.7 (Security), Page 40.
OAR 860-029-0123(12) (Cumulative Remedies)	Section 11.8 (Cumulative Remedies), Page 40.
OAR 860-029-0124(1) (Coordination between Qualifying Facility and Public Utility under Standard Power Purchase Agreements – Coordination with System)	Section 6.4 (Coordination with System), Pages 25-26.
OAR 860-029-0124(2) (Coordination between Qualifying Facility and Public Utility under Standard Power Purchase Agreements – Planned Outages)	Definition of "Planned Outage", Page 10; Section 6.5.1 (Planned Outages), Page 26; Exhibit I (NERC Event Types), Page 63.
OAR 860-029-0124(3) (Coordination between Qualifying Facility and Public Utility under Standard Power Purchase Agreements – Maintenance Outages)	Definition of "Maintenance Outage", Pages 8-9; Section 6.5.2 (Maintenance Outages), Pages 26; Exhibit I (NERC Event Types), Page 63.
OAR 860-029-0124(4) (Coordination between Qualifying Facility and Public Utility under Standard Power Purchase Agreements – Forced Outages)	Definition of "Forced Outage", Page 7; Section 6.5.3 (Forced Outages), Pages 26-27; Exhibit I (NERC Event Types), Page 63.
OAR 860-029-0124(5) (Coordination between Qualifying Facility and Public Utility under Standard Power Purchase Agreements – Notice of Emergency Deratings and Outages)	Section 6.5.4 (Notice of Deratings and Outages), Page 27.

Joint Utilities'

Oregon Standard Power Purchase Agreement

POWER PURCHASE AGREEMENT

BETWEEN

____

AND

UTILITY

This working draft is provided pursuant to [UTILITY NAME]'s Schedule XX. This working draft does not constitute a binding offer, does not form the basis for an agreement by estoppel or otherwise, and is conditioned upon satisfaction of all requirements of Schedule XX, including each party's receipt of all required internal approvals and any other necessary regulatory approvals.

(continued)

TABLE OF CONTENTS

(continued)

(continued)

(continued)

(continued)

EXHIBITS

(continued)

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT (this "Agreement"), is entered into between [COMPANY NAME], a/an [TYPE OF ORGANIZATIONAL ENTITY AND STATE OF ORGANIZATION] (the "Seller"), and [UTILITY NAME], a/n [TYPE OF ORGANIZATIONAL ENTITY AND STATE OF ORGANIZATION] ("Utility"). Seller and Utility are sometimes referred to in this Agreement collectively as the "Parties" and individually as a "Party."

RECITALS[1]

A. Seller intends to construct, own, operate and maintain a [___]-powered generating facility for the generation of electric energy located in [_______] County, Oregon, with a nameplate capacity rating of [__][2] MW (the "Facility"); and

B. Seller will operate the Facility as a Qualifying Facility ("QF"); and

C. Seller desires to sell, and Utility agrees to purchase, the Net Output delivered by the Facility in accordance with the terms and conditions of this Agreement; and

D. The rates, terms, and conditions in this Agreement are in accordance with the rates, terms, and conditions approved by the Commission for purchases from QFs.

AGREEMENT

NOW, THEREFORE, in consideration of the foregoing and the mutual promises below and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties mutually agree as follows:

[1] **Note to Form** – Recital A to be adjusted in case of PPA with operational QF: "Seller owns, operates and maintains a [___]-powered generating facility for the generation of electric energy located in [_______] County, Oregon, with a nameplate capacity rating of [__] MW (the "Facility")."

[2] **Note To Form** – Must be ten (10) MWAC or less.

(continued)

SECTION 1
DEFINITIONS, RULES OF INTERPRETATION

1.1 Defined Terms. Unless otherwise required by the context in which any term appears, initially capitalized terms used in this Agreement have the following meanings:

"Abandonment" means (a) the relinquishment of all possession and control of the Facility by Seller, or (b) if after commencement of the construction, testing, and inspection of the above-ground portions of the Facility (exclusive of road building), and prior to the Commercial Operation Date, there is a complete cessation of the construction, testing, and inspection of the Facility for ninety (90) consecutive days, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default by Utility, a request by Utility, or an event of Force Majeure.

"AC" means alternating current.

"Affiliate" means, with respect to any entity, each entity that directly or indirectly controls, is controlled by, or is under common control with, such designated entity, with "control" meaning the possession, directly or indirectly, of the power to direct management and policies, whether through the ownership of voting securities or by contract or otherwise. [Notwithstanding the foregoing, with respect to PacifiCorp, "Affiliate" only includes Berkshire Hathaway Energy Company and its direct, wholly-owned subsidiaries.]

"Agreement" is defined in the introductory paragraph above.

"Ancillary Services" has the meaning set forth in the Tariff. Ancillary Services shall include reactive power, but shall not include any Capacity Rights.

"As-built Supplement" is a supplement to Exhibit B and Exhibit C of this Agreement, as provided in Section 6.1, which provides the final "as-built" description of the Facility, including the Point of Delivery and, subject to the provisions of Section 6.1, identifies changes in equipment or Facility configuration, or other modifications to the information provided in Exhibit B and Exhibit C as of the Effective Date.

"Business Day" means any day on which banks in Portland, Oregon, are not authorized or required by Requirements of Law to be closed.

"Capacity Rights" means any current or future defined characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, including any of the same counted towards any current or future resource adequacy or reserve requirements, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce energy and any of those services necessary to support the transmission of electric power from Seller to Utility and to maintain reliable operations of the System, including voltage control, operating reserve, spinning reserve and reactive power. Capacity Rights do not include any Ancillary Services, Environmental Attributes, Tax Credits or other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility.

"Commercial Operation" means that the Nameplate Capacity Rating of the Facility is fully operational and reliable and the Facility is fully interconnected, fully integrated, and synchronized with the System, all of which are Seller's responsibility to receive or obtain, and which occurs when Seller has achieved the Milestones set forth in Section 2.2 and all of the following events (a) have occurred, and (b) remain

(continued)

simultaneously true and accurate as of the date and moment on which Seller gives Utility notice that Commercial Operation has occurred:

(i) Utility has received a letter addressed to Utility from a Licensed Professional Engineer licensed in the state of Oregon certifying: (1) the Nameplate Capacity Rating of the Facility at the anticipated time of Commercial Operation, and (2) that the Facility is able to generate electric energy in amounts expected by and consistent with the terms and conditions of this Agreement;

(ii) Utility has received a letter addressed to Utility from a Licensed Professional Engineer certifying that, in conformance with the requirements of the Generation Interconnection Agreement: (1) all required Interconnection Facilities have been constructed, (2) all required interconnection tests have been completed, and (3) the Facility is physically interconnected with the System in conformance with the Generation Interconnection Agreement;

(iii) Utility has received a letter from a Licensed Professional Engineer licensed in the state of Oregon addressed to Utility certifying that Seller has obtained or entered into all Required Facility Documents;

(iv) Utility has received a certificate from an officer of Seller stating that neither Seller nor the Facility are in violation of or subject to any liability under any Requirements of Law;

(v) Seller has satisfied its obligation to pay for any network upgrades or other interconnection costs required under the Generation Interconnection Agreement (as terms are defined in the Generation Interconnection Agreement);

(vi) Utility has received a copy of the executed Generation Interconnection Agreement and Transmission Agreements (as applicable);

(vii) In the case of an Off-System QF, Seller shall demonstrate that it has made arrangements sufficient to reserve Firm Delivery (as defined in Exhibit L) of Net Output up to the Maximum Delivery Rate to the Point of Delivery for the full term of the Agreement, which may be demonstrated by obtaining Firm Delivery or rights to obtain Firm Delivery (i.e., rollover rights) under the third-party Transmission Provider(s) tariff for the period covering the Term; and

(viii) Utility has received the Default Security, as applicable.

Seller must provide written notice to Utility stating when Seller believes that the Facility has achieved Commercial Operation and its Nameplate Capacity Rating accompanied by the documentation described above. Utility must respond to Seller's notice within ten (10) Business Days of receipt of a notice satisfying the requirements of the preceding sentence. If Utility does not respond to Seller's complying notice within such time period, the Commercial Operation Date will be the date of Utility's receipt of such complying notice from Seller. If Utility informs Seller within such ten (10) Business Day period that Utility believes the Facility has not achieved Commercial Operation, identifying the specific areas of deficiency, Seller must address the concerns stated in Utility's deficiency notice to the reasonable satisfaction of Utility; the Commercial Operation Date will then be the date that the matters identified in Utility's

(continued)

deficiency notice have been addressed to Utility's reasonable satisfaction.[3]

"Commercial Operation Date" means the date that Commercial Operation is achieved for the Facility but in no event earlier than ninety (90) days before the Scheduled Commercial Operation Date unless Utility, after undertaking reasonable efforts to obtain transmission service, is able to accept delivery from Seller earlier; provided that in no event will the Commercial Operation Date occur earlier than one hundred eighty (180) days before the Scheduled Commercial Operation Date.[4]

"Commission" means the Public Utility Commission of Oregon.

"Conditional DNR Notice" is defined in Section 4.2.

"Contract Interest Rate" means the lesser of (a) the highest rate permitted under Requirements of Law or (b) 200 basis points per annum plus the rate per annum equal to the publicly announced prime rate or reference rate for commercial loans to large businesses in effect from time to time quoted by Citibank, N.A. as its "prime rate." If a Citibank, N.A. prime rate is not available, the applicable prime rate will be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest is being paid.

"Contract Price" means the applicable price, expressed in $/MWh, for Net Output, Capacity Rights, Ancillary Service, and Environmental Attributes, which shall be Standard Fixed Pricing or Renewable Fixed Pricing, as applicable during the Fixed Price Period, as stated in Exhibit J, and otherwise shall be Firm Electric Market Pricing.[5]

"Contract Year" means a twelve (12) month period commencing at 00:00 hours [Pacific Prevailing Time/Mountain Prevailing Time] on January 1 and ending on 24:00 hours [PPT/MPT] on December 31; provided, however, that the first Contract Year shall commence on the Effective Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

"Credit Requirements" means (1) a senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of (a) 'BBB+' or greater from S&P, or (b) 'Baa1' or greater form Moody's;

[3] **Note to Form** – This definition and references to "Commercial Operation" to be deleted in case of PPA with operational QF and replaced with definition of and references to "Initial Delivery". "Initial Delivery" means the later of (i) the date on which Seller's obligations under Section 2.2 are satisfied; (ii) the date on which Utility provides written notification to Seller that the Facility has been designated a Network Resource as provided under Section 4.2; and (iii) the Scheduled Initial Delivery Date.

[4] **Note to Form** – This definition and references to "Commercial Operation Date" to be deleted in case of PPA with operational QF and replaced with definition of and references to "Initial Delivery Date". "Initial Delivery Date" means the date on which Initial Delivery occurs.

[5] **Note to Form** – The Contract Price in this form of agreement assumes that Seller elects Standard Fixed Pricing or Renewable Fixed Pricing for the Fixed Price Period, in each case, as determined at the time of contract execution. This form of Agreement will be revised for solar QFs with a Nameplate Capacity Rating of more than three (3) MW and less than ten (10) MW, which are not eligible for Standard Fixed Pricing or Renewable Fixed Pricing.

(continued)

provided that if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baa1' from S&P or Moody's; or (2) if (1) (a) or (b) is not available, an equivalent rating as determined by Utility through an internal process review and utilizing a credit scoring model of two full years of audited financial statements (including balance sheet, income statement, statement of cash flows, and accompanying footnotes) which information is evaluated considering (i) the type of generation resource, the size of the resource the Scheduled Commercial Operation Date and the term of the Agreement and (ii) at minimum, profitability, cash flow, liquidity and financial leverage metrics.

"Cure Period Deadline" means, in the case of failure to achieve Commercial Operation by the Scheduled Commercial Operation Date, the date that occurs one (1) year following the Scheduled Commercial Operation Date.[6]

"Default Security" is an amount equal to fifty dollars ($50) per kW of the final Nameplate Capacity Rating.

"Delay Damages" for any given day in a given month are equal to (a) the Expected Monthly Net Output for such month, expressed in MWhs per month, divided by the number of days in such month, multiplied by (b) Utility's Cost to Cover. To the extent Utility reasonably incurs additional costs to purchase replacement power, including, for example, transmission charges to deliver replacement energy to the Point of Delivery, and, to the extent Seller is required to convey Environmental Attributes to Utility under this Agreement during any portion of the delay period, and Utility reasonably incurs additional costs to acquire replacement Environmental Attributes, such sums, in each case as applicable, shall be added to the Delay Damages. Delay Damages are to be aggregated and invoiced as a monthly sum.

"Effective Date" is defined in Section 2.1.

"Electric System Authority" means each of NERC, WECC, WREGIS, an RTO, a regional or sub-regional reliability council or authority, and any other similar council, corporation, organization or body of recognized standing with respect to the operations of the electric system in the WECC region, as such are applicable to the Seller or Utility.

"Environmental Attributes" means any and all claims, credits, benefits, emissions reductions, offsets, and allowances associated with the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water, including green tags and renewable energy certificates. Environmental Attributes include: (a) any avoided emissions of pollutants to the air, soil, or water such as sulfur oxides, nitrogen oxides, carbon monoxide, and other pollutants; and (b) any avoided emissions of carbon dioxide, methane, and other greenhouse gases that have been determined by any Governmental Authority to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere. Environmental Attributes do not include (i) Tax Credits or other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility, (ii) matters designated by Utility as sources of liability, or (iii) adverse wildlife or environmental impacts.

"Environmental Contamination" means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of federal, state, or local laws or regulations, and present a material risk under federal, state, or local laws or regulations that the Premises will not be available or usable for the purposes contemplated by this Agreement.

[6] **Note to Form** – This definition to be deleted in case of PPA with operational QF.

(continued)

"Event of Default" is defined in Section 11.1.

"Excused Delay" means the failure of Seller to achieve Commercial Operation on or before the Scheduled Commercial Operation Date, but only to the extent such failure is caused by an event of Force Majeure or an Event of Default by Utility, a default by Utility under the Generation Interconnection Agreement or related interconnection study agreement(s) for Seller's Facility, including a default resulting from any breach by Utility of any obligation to meet a material deadline included in such agreement(s), or Utility's violation of applicable tariff provisions governing the interconnection of Seller's Facility; provided that the duration of any Excused Delay shall not extend to any period of delay that could have been prevented had Seller taken mitigating actions using commercially reasonable efforts.

"Expected Monthly Net Output" means the estimated monthly Net Output as determined in Exhibit A.

"Expected Net Output" means [_____] MWh of Net Output in the first full Contract Year reduced, as applicable, by an annual degradation factor of [__] per Contract Year, measured at the Point of Delivery. Seller estimates that the Net Output will be delivered during each Contract Year according to the Expected Monthly Net Output provided in Exhibit A, as reduced each Contract Year, as applicable, by the annual degradation factor. Expected Net Output assumes a reduction of [_____] MWh of Net Output for Planned Outages.

"Facility" is defined in the Recitals and is more fully described in attached Exhibit B and includes all equipment, devices, associated appurtenances owned, controlled, operated, and managed by Seller in connection with, or to facilitate, the production, storage, generation, transmission, delivery, or furnishing of electric energy by Seller to Utility and required to interconnect with the System.

"FERC" means the Federal Energy Regulatory Commission.

"Firm Electric Market Pricing" means the hourly value calculated based on the average prices reported by the Intercontinental Exchange, Inc. ("ICE") Day-Ahead Mid-C On-Peak Index and the ICE Day-Ahead Mid-C Off-Peak Index (each an "ICE Index") for a given day, weighted by the count of hours for each ICE Index on such day, multiplied by the hourly CAISO day-ahead market locational marginal price for the ["Utility CAISO LMP"[7]] location and divided by the average of the same CAISO index over all hours in such day. If applicable, the resulting value will be reduced by the integration costs specified in the then-current Utility Oregon Schedule XX as applicable to the Facility. If any index is not available for a given period, Firm Electric Market Pricing will mean the average price derived from days in which all published data is available, for the same number of days immediately preceding and immediately succeeding the period in which an index was not available, regardless of which days of the week are used for this purpose. If Firm Electric Market Pricing or its replacement or any component of that index or its replacement ceases to be published or available, or useful for its intended purpose under this Agreement, during the Term, the Parties must agree upon a replacement index or component that, after any necessary adjustments, provides the most reasonable substitute quotation of the hourly price of electricity for the applicable periods.

[7] **Note to Form** – Each Utility to specify applicable LMP.

(continued)

"Fixed Price Period" means the portion of the Term commencing on the Fixed Price Period Start Date and ending on the Fixed Price Period End Date.[8]

"Fixed Price Period End Date" means (i) if Seller selects a Scheduled Commercial Operation Date that occurs no later than three (3) years from the Effective Date or a Scheduled Commercial Operation Date that occurs between three (3) and five (5) years from the Effective Date and aligns with Utility Transmission's estimate in an interconnection study of the date of completion of the interconnection for the Facility (as of the Effective Date or otherwise as selected under Section 2.9), the last day of the fifteen (15)-year period following the Fixed Price Period Start Date; or (ii) if Seller selects a Scheduled Commercial Operation Date that occurs between three (3) and five (5) years from the Effective Date for any other reason, the last day of the eighteen (18)-year period following the Effective Date; provided that the Fixed Price Period End Date described in clause (ii) shall be extended on a day-for-day basis for each day that the Scheduled Commercial Operation Date is extended for Excused Delay under Section 2.8.

"Fixed Price Period Start Date" means the earlier to occur of the Commercial Operation Date or the Scheduled Commercial Operation Date.

"Force Majeure" is defined in Section 14.1.

"Forced Outage" means (i) an outage that requires immediate removal of a unit from service, another outage state or a reserve shutdown state; (ii) an outage that does not require immediate removal of a unit from the in-service state but requires removal within six (6) hours; or (iii) an outage that can be postponed beyond six (6) hours but requires that a unit be removed from the in-service state before the end of the next weekend. Forced Outages include NERC Event Types U1, U2, or U3, as provided in attached Exhibit I. A Forced Outage specifically excludes any Maintenance Outage or Planned Outage.

"Generation Interconnection Agreement" means the generator interconnection agreement entered into separately between Seller and Interconnection Provider concerning the Interconnection Facilities.

"Governmental Authority" means any supranational, federal, state, or other political subdivision thereof, having jurisdiction over Seller, Utility, or this Agreement, including any municipality, township, or county, and any entity or body exercising executive, legislative, judicial, regulatory, or administrative functions of or pertaining to government, including any corporation or other entity owned or controlled by any of the foregoing.

"Hazardous Materials" means any waste or other substance that is listed, defined, designated, or classified as or determined to be hazardous under or pursuant to any environmental law or regulation.

"Indemnified Party" is defined in Section 6.2.3(b).

"Interconnection Facilities" means all the facilities installed, or to be installed under the Generation Interconnection Agreement, including electrical transmission lines, interconnection upgrades, network upgrades, transformers and associated equipment, substations, relay and switching equipment, and safety equipment.

[8] **Note to Form** – The definition of Fixed Price Period assumes that Seller elects Standard Fixed Pricing or Renewable Fixed Pricing for the Fixed Price Period.

(continued)

"Interconnection Provider" means the interconnection provider specified in Exhibit C.

"KW" means kilowatt.

"Lender" means an entity lending money or extending credit (including any financing lease, monetization of tax benefits, transaction with a tax equity investor, back leverage financing, or credit derivative arrangement) to Seller or Seller's Affiliates (a) for the construction, term or permanent financing or refinancing of the Facility, (b) for working capital or other ordinary business requirements for the Facility (including for the maintenance, repair, replacement, or improvement of the Facility), (c) for any development financing, bridge financing, credit support, and related credit enhancement or interest rate, currency, weather, or Environmental Attributes in connection with the development, construction, or operation of the Facility, or (d) for the purchase of the Facility and related rights from Seller.

"Letter of Credit" means an irrevocable standby letter of credit in a form reasonably acceptable to Utility, naming Utility as the party entitled to demand payment and present draw requests that:

(1) is issued by a Qualifying Institution;

(2) by its terms, permits Utility to draw up to the face amount thereof for the purpose of paying any and all amounts owing by Seller under this Agreement;

(3) permits Utility to draw the entire amount available if such letter of credit is not renewed or replaced at least thirty (30) Business Days prior to its stated expiration date;

(4) permits Utility to draw the entire amount available if such letter of credit is not increased or replaced as and when provided in Section 8;

(5) is transferable by Utility to any party to which Utility may assign this Agreement; and

(6) remains in effect for at least ninety (90) days after the end of the Term.

"Liabilities" is defined in Section 12.1.1.

"Licensed Professional Engineer" means a person proposed by Seller and acceptable to Utility in its reasonable judgment who (a) to the extent mandated by Requirements of Law is licensed to practice engineering in the appropriate engineering discipline for the required certification being made, in the United States, and in all states for which the person is providing a certification, evaluation or opinion with respect to matters or Requirements of Law specific to such state, (b) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation, or opinion, (c) is not an employee of Seller or an Affiliate, and (d) is not a representative of a consulting engineer, contractor, designer, or other individual involved in the development of the Facility, or a representative of a manufacturer or supplier of any equipment installed in the Facility.

"Maintenance Outage" means an outage that can be deferred beyond the next weekend but requires that the unit be removed from service before the next Planned Outage. A Maintenance Outage can occur any time during the year, has a flexible start date, may or may not have a predetermined duration and is usually shorter than a Planned Outage. Maintenance Outages include NERC Event Type MO, as

(continued)

provided in attached Exhibit I, and include any outage involving ten percent (10%) of the Facility's Net Output that is not a Forced Outage or a Planned Outage.

"Market Operator" means the California Independent System Operator ("CAISO") or any other entity performing the market operator function for any organized day-ahead or intra-hour market.

"Maximum Delivery Rate" means the maximum hourly rate of delivery of Net Output in MWh from the Facility to the Point of Delivery, calculated as the lower of the Net Output delivered in an hour accruing at an average rate equivalent to the actual Nameplate Capacity Rating, as stated in Exhibit A, or the maximum rate of delivery that is permissible under the Generation Interconnection Agreement.

"Moody's" means Moody's Investor Services, Inc.

"Mountain Prevailing Time" or "MPT" means Mountain Standard Time or Mountain Daylight Time, as applicable in Oregon on the day in question.

"MW" means megawatt.

"MWh" means megawatt-hour.

"Nameplate Capacity Rating" means the maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), measured at the Point of Interconnection, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant. The Nameplate Capacity Rating of the Facility is [__] MW, as reflected in the Seller's FERC Form 556.

"NERC" means the North American Electric Reliability Corporation.

"Net Output" means all energy and capacity produced by the Facility, less station service, transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any.

"Network Resource" is defined in the Tariff.

"Non-Fixed Price Period" means the period of the Term commencing on the first (1st) day following the Fixed Price Period End Date and ending on the last day of the Term.[9]

"Off-Peak Hours" has the meaning as provided in Utility's Schedule XX, as attached in Exhibit J.

"Off-System QF" means a QF that is not directly interconnected to Utility's transmission or distribution system and schedules delivery of Net Output to a Point of Delivery on Utility's transmission system.

"On-Peak Hours" has the meaning as provided in Utility's Schedule XX, as attached in Exhibit J.

[9] **Note to Form** – The definition of Non-Fixed Price Period assumes that Seller elects Standard Fixed Pricing or Renewable Fixed Pricing for the Fixed Price Period.

(continued)

"On-System QF" means a QF that is directly interconnected to Utility's transmission or distribution system.

"Output" means all energy produced by the Facility.

"Pacific Prevailing Time" or "PPT" means Pacific Standard Time or Pacific Daylight Time, as applicable in Oregon on the day in question.

"Party" and "Parties" are defined in the Recitals.

"Performance Guarantee" has the meaning set forth in Section 6.15.

"Permits" means the permits, licenses, approvals, certificates, entitlements, and other authorizations issued by Governmental Authorities required for the construction, ownership, or operation of the Facility or occupancy of the Premises.

"Planned Outage" means an outage that is scheduled well in advance and is of a predominate duration, and includes a NERC Event Type PO, as provided in attached Exhibit I, and specifically excludes any Maintenance Outage or Forced Outage.

"Point of Delivery" means (i) for Off-System QFs, the point on the System where Seller will deliver Net Output to the Utility as described in Exhibit C; and (ii) for On-System QFs, the Point of Delivery is the point of interconnection between the Facility and the System, as specified in the Generation Interconnection Agreement and as further described in Exhibit C.

"Premises" means the real property on which the Facility is or will be located, as more fully described on Exhibit B.

"Project Development Security" is an amount equal to one hundred-fifty dollars ($150) per kW of the Nameplate Capacity Rating.[10]

"Prudent Electrical Practices" means any of the practices, methods and acts engaged in or approved by a significant portion of the independent electric power generation industry for facilities of similar size and characteristics or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety, and expedition.

"PURPA" means the Public Utility Regulatory Policies Act of 1978.

"QF" means "Qualifying Facility," as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

"Qualifying Institution" means a United States commercial bank or trust company organized under the laws of the United States of America or a political subdivision thereof having assets of at least $10,000,000,000 (net of reserves) and a credit rating on its long-term senior unsecured debt of at least 'A' from S&P and 'A2' from Moody's.

[10] **Note to Form** – This definition to be deleted in case of PPA with operational QF.

(continued)

"Renewable Fixed Pricing" means the applicable renewable fixed avoided cost prices as published in Utility's Oregon Schedule XX.

"Renewable Resource Deficiency Period" means the period commencing on [____].

"Renewable Resource Sufficiency Period" means the period from the Effective Date until the Renewable Resource Deficiency Period.

"Replacement Power Costs" means for each day for which the Utility's Cost to Cover is calculated, stated as an amount per MWh, the Firm Electric Market Pricing.

"Required Facility Documents" means the Permits and other authorizations, rights, and agreements necessary for construction, ownership, operation, and maintenance of the Facility, and to deliver the Net Output to Utility in accordance with this Agreement and Requirements of Law, including those listed in Exhibit D.

"Requirements of Law" means any applicable federal, state, and local law, statute, regulation, rule, action, order, code or ordinance enacted, adopted, issued or promulgated by any Governmental Authority (including those pertaining to electrical, building, zoning, environmental and wildlife protection, and occupational safety and health).
"RTO" means any entity (including an independent system operator) that becomes responsible as system operator for, or directs the operation of, the System.

"S&P" means Standard & Poor's Rating Group (a division of S&P Global, Inc.).

"Schedule XX" means Utility's Oregon Schedule No. XX as attached in Exhibit J, and as approved by the Commission on the Effective Date.

"Schedule Recovery Plan" means a written recovery plan, approved by Utility, an initial draft of which Seller shall submit to Utility (i) within five (5) Business Days after Seller's receipt of a written request from Utility in the event of Seller's Abandonment of the Facility under clause (b) of the definition thereof or (ii) by the Scheduled Commercial Operation Date in the event of Seller's failure to achieve Commercial Operation by the Scheduled Commercial Operation Date. The Schedule Recovery Plan shall include a detailed plan to complete all necessary work to achieve Commercial Operation by the Scheduled Commercial Operation Date, in the case of Abandonment, or, in the case of failure to achieve Commercial Operation by the Scheduled Commercial Operation Date, by the Cure Period Deadline. Upon its receipt of a draft recovery plan, Utility shall promptly approve or submit reasonable revisions to the draft. Seller promptly shall incorporate any such revisions into the draft recovery plan and resubmit it to Utility for approval. Upon approval of the revised recovery plan by Utility, Seller shall diligently prosecute the work in accordance with the Schedule Recovery Plan. Seller shall be responsible for any costs or expenses incurred by Seller as a result of the formulation and implementation of the Schedule Recovery Plan. Approval by Utility of such plan shall not be deemed in any way to have relieved Seller of its obligations under this Agreement relating to the failure to timely achieve Commercial Operation by the Scheduled Commercial Operation Date or be a basis for any increase in the Contract Price or other claim against Utility.

"Scheduled Commercial Operation Date" means [______], subject to extension for Excused Delay as provided in Section 2.8, in the event Seller exercises its option under Section 2.9 and as provided in Section 4.2. The Scheduled Commercial Operation Date must be a date that occurs ninety (90) days or

(continued)

more after the Effective Date but no later than the last day of the five-year period following the Effective Date (except to the extent extended for Excused Delay or under Section 4.2).[11]

"Seller" is defined in the Recitals.

"Seller Indemnitees" is defined in Section 12.1.2.

"Seller's Cost to Cover" means the positive difference, if any, between (a) the Contract Price per MWh, and (b) the net proceeds per MWh actually realized by Seller from the sale to a third party of Net Output not purchased by Utility as required under this Agreement.

"Standard Fixed Pricing" means the standard fixed avoided cost prices as published in Utility's Oregon Schedule XX.

"System" means the electric transmission substation and transmission or distribution facilities owned, operated, or maintained by the Transmission Provider, the Interconnection Provider, and/or Utility Transmission, as the context requires, and includes the circuit reinforcements, extensions, and associated terminal facility reinforcements or additions required to interconnect the Facility, all as provided in the Generation Interconnection Agreement.

"Tariff" means Utility's Open Access Transmission Tariff on file with FERC, as such tariff is revised from time to time.

"Tax Credits" means any state, local, or federal production and investment tax credits, tax deductions, or other tax benefits specific to the production of renewable energy or investments in renewable energy facilities.

"Term" is defined in Section 2.1.

"Termination Damages" is defined in Section 11.5.

"Transmission Agreements" means any transmission service agreement required to deliver the Net Output of the Facility to the Point of Delivery. Such transmission service agreements must have a start date that is on or before the Commercial Operation Date of the Facility and continue through, or have rollover rights for, the entire Term.

"Transmission Provider" means Utility Transmission or, as the context requires, a third-party transmission provider (i.e., in the case of an Off-System QF), including the business unit responsible for the safe and reliable operation of the Transmission Provider's balancing authority area(s).

"Utility" is defined in the Recitals, and explicitly excludes Utility Transmission.

"Utility Indemnitees" is defined in Section 12.1.1.

[11] **Note to Form** – This definition and references to "Scheduled Commercial Operation Date" to be deleted in case of PPA with operational QF and replaced with definition of and references to "Scheduled Initial Delivery Date." "Scheduled Initial Delivery Date" means [____].

(continued)

"Utility Representatives" is defined in Section 6.14.

"Utility Transmission" means [UTILITY NAME], a/an [TYPE OF ORGANIZATIONAL ENTITY AND STATE OF ORGANIZATION], acting in its interconnection or transmission function capacity.

"Utility's Cost to Cover" means for any day for which Utility's Cost to Cover is calculated, stated as an amount per MWh, the lower of (i) the positive difference between the Replacement Power Costs less the Contract Price in effect, and (ii) the Contract Price in effect.

"WECC" means the Western Electricity Coordinating Council.

"WREGIS" means the Western Renewable Energy Generation Information System or successor organization in case WREGIS is ever replaced.

"WREGIS Certificate" means "Certificate" as defined by WREGIS in the WREGIS Operating Rules dated [______________________].

"WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS, dated [______________________].

1.2 Rules of Interpretation.

1.2.1 General. Unless otherwise required by the context in which any term appears, (a) the singular includes the plural and vice versa; (b) references to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" are to articles, sections, schedules, appendices or exhibits of this Agreement; (c) all references to a particular entity or an electricity market price index include a reference to such entity's or index's successors; (d) "herein," "hereof" and "hereunder" refer to this Agreement as a whole; (e) all accounting terms not specifically defined in this Agreement must be construed in accordance with generally accepted accounting principles, consistently applied; (f) the masculine includes the feminine and neuter and vice versa; (g) "including" means "including, without limitation" or "including, but not limited to"; (h) all references to a particular law or statute mean that law or statute as amended from time to time; (i) all references to energy or capacity are to be interpreted as utilizing alternating current, unless expressly stated otherwise; and (j) the word "or" is not necessarily exclusive. Reference to "days" means calendar days, unless expressly stated otherwise in this Agreement.

1.2.2 Terms Not to be Construed For or Against Either Party. Each term in this Agreement must be construed according to its fair meaning and not strictly for or against either Party.

1.2.3 Headings. The headings used for the sections and articles of this Agreement are for convenience and reference purposes only and in no way affect the meaning or interpretation of the provisions of this Agreement.

1.2.4 Interpretation with FERC Orders. Each Party conducts its operations in a manner intended to comply with FERC Order No. 717, Standards of Conduct for Transmission Providers, and its companion orders, requiring the separation of its transmission and merchant functions. Moreover, the Parties acknowledge that Utility Transmission offers transmission service on its System in a manner intended to comply with FERC policies and requirements relating to the provision of open-access transmission service.

(continued)

(a) The Parties acknowledge and agree that the Generation Interconnection Agreement is a separate and free-standing contract and that the terms of this Agreement are not binding upon the Interconnection Provider.

(b) Notwithstanding any other provision in this Agreement, except as expressly provided herein, nothing in the Generation Interconnection Agreement, nor any other agreement between Seller on the one hand and Transmission Provider or Interconnection Provider on the other hand, nor any alleged event of default under the Generation Interconnection Agreement, will alter or modify the Parties' rights, duties, and obligations in this Agreement. This Agreement will not be construed to create any rights between Seller and the Interconnection Provider or between Seller and the Transmission Provider.

(c) Seller acknowledges that, for purposes of this Agreement, consistent with FERC Order No. 717, Standards of Conduct for Transmission Providers, and its companion orders, the Interconnection Provider and Transmission Provider are deemed separate entities and separate contracting parties from Utility. Seller acknowledges that Utility, acting in its merchant capacity function or otherwise as purchaser in this Agreement, has no responsibility for or control over Interconnection Provider or Transmission Provider.

SECTION 2
TERM; MILESTONES

2.1 Term. This Agreement is effective when executed and delivered by both Parties (the "Effective Date") and, unless earlier terminated as provided in this Agreement, shall remain in effect until the last day of the twenty (20)-year period following the first to occur of the Commercial Operation Date or the Scheduled Commercial Operation Date (the "Term").[12]

2.2 Milestones.[13] Time is of the essence in the performance of this Agreement, and Seller's completion of the Facility and delivery of Net Output by the Scheduled Commercial Operation Date is critically important. Therefore, Seller must achieve the milestones provided in (a) through (e) below at the times so indicated.

(a) Seller must provide a fully executed and effective Generation Interconnection Agreement and

[12] **Note to Form** – This Section assumes Seller elects a twenty (20)-year term. If Seller chooses a shorter Term, this provision would require revision.

[13] **Note to Form** – This Section will be adjusted in case of PPA with operational QF, and the milestones in (a) through (e) are to be replaced with the following:

(a) By the Effective Date, Seller shall provide Utility with (i) a copy of an executed Generation Interconnection Agreement, or wheeling agreement, as applicable, which shall be consistent with all material terms and requirements of this Agreement, (ii) the Required Facility Documents, and (iii) an executed copy of Exhibit G – Seller's Authorization to Release Generation Data to Utility.

(b) By the date that occurs thirty (30) days after the Effective Date, Seller shall provide Default Security if required under this Agreement.

(c) In the case of an Off-System QF, Seller shall demonstrate that it has made arrangements

(continued)

Transmission Agreement, if applicable, to Utility before the Scheduled Commercial Operation Date.

(b) If and to the extent required by this Agreement, on or before the one hundred and twentieth (120th) day following the Effective Date, Seller must post the Project Development Security.

(c) If and to the extent required by this Agreement, on or before the Commercial Operation Date, Seller must post the Default Security.

(d) Seller must provide Utility with documentation showing that Seller has obtained retail electric service for the Facility before the Commercial Operation Date.

(e) Seller must cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date.

2.3 Obligation to Report on Certain Project Milestones.[14] Within thirty (30) days of completion of each project milestone listed below, but not later than the date specified for achievement of each such milestone, Seller shall notify Utility in writing of the achievement of the milestone, attaching evidence demonstrating such achievement. If any milestone is not achieved on or before the dates specified below, then Seller shall: (a) inform Utility of a revised projected date for the achievement of such milestone, and any impact on the timing of the Commercial Operation Date (and on any other project milestone); and (b) provide Utility with a written report containing Seller's analysis of the reasons behind the failure to meet the original project milestone deadline and whether remedial actions are necessary or appropriate, and describing any remedial actions that Seller intends to undertake to ensure the timely achievement of the Commercial Operation Date by the Scheduled Commercial Operation Date. These milestones include:

(a) If Seller has not received an interconnection study as of the Effective Date, receipt of an interconnection study by [____________________].

(b) If Seller does not have a signed Generation Interconnection Agreement as of the Effective Date, receipt of a Generation Interconnection Agreement by [____________________].

(c) If Seller has not issued a notice to proceed with construction of the Facility as of the Effective Date, issuance of a notice to proceed with construction (or its equivalent) of the Facility by [____________________].

2.4 Delay Damages; Schedule Recovery Plan.

(a) If Commercial Operation is not achieved on or before the Scheduled Commercial Operation Date,

---

sufficient to reserve Firm Delivery (as defined in Exhibit L) of Net Output up to the Maximum Delivery Rate to the Point of Delivery for the full term of the Agreement, which may be demonstrated by obtaining Firm Delivery or rights to obtain Firm Delivery (i.e. rollover rights) under the third-party Transmission Provider(s) tariff for the period covering the Term.

(d) Seller must cause Initial Delivery to occur on or before the Scheduled Initial Delivery Date.

[14] **Note to Form** – To be deleted in case of PPA with operational QF.

(continued)

Seller must (i) pay to Utility Delay Damages from and after the Scheduled Commercial Operation Date up to, but not including, the earlier to occur of the date that the Facility achieves Commercial Operation or the date of termination as provided in Sections 11.1.2(b) and 11.3, if applicable, and (ii) deliver a Schedule Recovery Plan to Utility no later than the Scheduled Commercial Operation Date.[15]

(b) If the Facility does not achieve Commercial Operation within one year following the Scheduled Commercial Operation Date, in addition to assessing Delay Damages, Utility may terminate this Agreement under, and subject to, Section 11.1.2(b).[16]

2.5 Damages Calculation. Each Party agrees that the damages Utility would incur due to Seller's delay in achieving Commercial Operation are difficult or impossible to predict with certainty, and that it is impractical and difficult to assess actual damages in the circumstances stated. Delay Damages, however, fairly represent the Parties' expectations for actual damages. Except with respect to Utility's termination rights and as otherwise provided in Section 11.5, Delay Damages are Utility's exclusive remedy for Seller's delay in achieving Commercial Operation.

2.6 Damages Invoicing. By the tenth (10th) day following the end of the calendar month in which Delay Damages begin to accrue and continuing on the tenth (10th) day of each subsequent calendar month while such Delay Damages continue to accrue, Utility will deliver to Seller an invoice for the amount of Delay Damages due Utility. No later than ten (10) days after receiving such an invoice and subject to Sections 10.3 and 10.4, Seller must pay to Utility, by wire transfer of immediately available funds to an account specified in writing by Utility, the amount stated in such invoice.

2.7 Utility's Right to Monitor.[17] During the Term, Seller will allow Utility to monitor and will provide monthly updates to Utility concerning (a) the progress of Seller regarding the acquisition, design, financing, engineering, construction, and installation of the Facility, and (b) the contractors' performance of tests required to achieve Commercial Operation. Seller must provide Utility at least one hundred and twenty (120) days prior notice of each such performance test. Notwithstanding the foregoing, nothing in this Agreement will be construed to require Utility to monitor Seller's development of the Facility or to review, comment on, or approve any contract between Seller and a third party.

2.8 Excused Delay. If Seller fails to achieve Commercial Operation on or before the Scheduled Commercial Operation Date due to an Excused Delay, the Scheduled Commercial Operation Date shall be deemed extended on a day-for-day basis to match the duration of such Excused Delay, subject to the right to terminate pursuant to Section 14.5 in the event that the Excused Delay is caused by a Force Majeure event. Upon the request of Seller, and provided that the existence or duration of any Excused

[15] **Note to Form** – For PPAs with operational QFs, Section 2.4(a) to be deleted and replaced with the following provision: "If Initial Delivery is not achieved on or before the Scheduled Initial Delivery Date, Seller must (i) pay to Utility Delay Damages from and after the Scheduled Initial Delivery Date up to, but not including, the earlier to occur of the date that the Facility achieves Initial Delivery or the date of termination as provided in Section 11.1.2(b) and 11.3, if applicable."

[16] **Note to Form** – For PPAs with operational QFs, Section 2.4(b) to be deleted and replaced with the following provision: "If Initial Delivery does not occur within the cure period prescribed in Section 11.1.2(b), in addition to assessing Delay Damages, Utility may terminate this Agreement as provided therein."

[17] **Note to Form** – To be deleted in case of PPA with operational QF.

(continued)

Delay is not the subject of a good faith dispute between the Parties and no Seller Event of Default has occurred and is continuing, Utility agrees to provide reasonable assurances to Seller's Lenders and other financial institutions that the Scheduled Commercial Operation Date has been extended under this Section 2.8.

2.9 Option to Extend Scheduled Commercial Operation Date or Terminate.[18] If Seller receives its first interconnection study results from Utility within the six-month period following the Effective Date (or restudy results that indicate a material increase in the estimated completion date for the required Interconnection Facilities or the cost of interconnection), anytime within such six-month period, Seller may elect by written notice to Utility:

(a) To extend the Scheduled Commercial Operation Date if the estimated completion date for the construction of Interconnection Facilities described in such study occurs after the then-current Scheduled Commercial Operation Date; provided that the extended Scheduled Commercial Operation may not occur after the last day of the five-year period following the Effective Date; or

(b) To terminate this Agreement if Seller determines in its reasonable judgment that the estimated costs to interconnect the Facility to the Interconnection Provider's System renders the project uneconomic; provided that Seller shall be liable to Utility for damages incurred by Utility up until the date of termination, which damages may be taken from the Project Development Security posted by Seller.

SECTION 3
REPRESENTATIONS AND WARRANTIES

3.1 Mutual Representations and Warranties. Each Party represents and warrants to the other that:

3.1.1 Organization. It is duly organized and validly exists under the laws of the State of its organization.

3.1.2 Authority. It has the requisite power and authority to enter this Agreement and to perform according to the Agreement's terms.

3.1.3 Corporate Actions. It has taken all corporate actions required to be taken by it to authorize the execution, delivery, and performance of this Agreement and the consummation of the transactions contemplated.

3.1.4 No Contravention. The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, security instrument or undertaking, or other material agreement to which it is a party or by which it is bound, or any valid order of any court, or any regulatory agency or other Governmental Authority having authority to which it is subject.

3.1.5 Valid and Enforceable Agreement. This Agreement is a valid and legally binding obligation of it, enforceable in accordance with its terms, except as enforceability may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

[18] **Note to Form** – To be deleted in case of PPA with operational QF.

(continued)

3.2 Seller's Further Representations, Warranties and Covenants. Seller further represents, warrants, and covenants to Utility that:

3.2.1 Authority. Seller (a) has (or will have prior to the Commercial Operation Date) all required regulatory authority to make wholesale sales from the Facility; (b) has the power and authority to own and operate the Facility and be present upon the Premises for the Term; and (c) is duly qualified and in good standing under the laws of each jurisdiction where its ownership, lease or operation of property, or the conduct of its business requires such qualification.

3.2.2 No Contravention. The execution, delivery, performance, and observance by Seller of its obligations in this Agreement do not and will not:

(a) contravene, conflict with, or violate any provision of any material Requirements of Law presently in effect having applicability to either Seller or any owner of Seller;

(b) require the consent or approval of or material filing or registration with any Governmental Authority or other person other than consents and approvals which are (i) provided in Exhibit D or (ii) required in connection with the construction or operation of the Facility and expected to be obtained in due course; or

(c) result in a breach of or constitute a default under any provision of (i) any security issued by Seller or any owner of Seller, the effect of which would materially and adversely affect Seller's performance of, or ability to perform, its obligations in this Agreement, or (ii) any material agreement, instrument or undertaking to which either Seller or any owner or other Affiliate of Seller is a party or by which the property of either Seller or any owner or other Affiliate of Seller is bound, the effect of which would materially and adversely affect Seller's performance of, or ability to perform, its obligations in this Agreement.

3.2.3 Required Facility Documents. All Required Facility Documents as of the Effective Date are listed in Exhibit D. Pursuant to the Required Facility Documents, Seller holds as of the Effective Date, or will hold by the Commercial Operation Date (or such other later date as may be specified under Requirements of Law), and will maintain for the Term all Required Facility Documents. The anticipated use of the Facility complies with all applicable restrictive covenants affecting the Premises. Following the Commercial Operation Date, Seller must promptly notify Utility of any additional Required Facility Documents. If reasonably requested by Utility, Seller must provide copies of any or all Required Facility Documents.

3.2.4 Delivery of Energy; Accurate Nameplate Capacity Rating. As of the Commercial Operation Date, Seller will hold all rights sufficient to enable Seller to deliver Net Output at the Nameplate Capacity Rating from the Facility to the Point of Delivery pursuant to this Agreement throughout the Term.

3.2.5 Control of Premises. Seller has all legal rights necessary for the Seller to enter upon and occupy the Premises for the purpose of constructing, operating, and maintaining the Facility for the Term. All leases of real property required for the operation of the Facility or the performance of any obligations of Seller in this Agreement are identified in Exhibit E. Seller must maintain all leases or other land grants necessary for the construction, operation, and maintenance of the Facility. Upon request by Utility, Seller must provide copies of the memoranda of lease recorded in connection with the development of the Facility.

(continued)

3.2.6 Litigation. No litigation, arbitration, investigation, or other proceeding is pending or, to the best of Seller's knowledge, threatened against Seller or any Affiliate of Seller, with respect to this Agreement, the Facility, or the transactions contemplated in this Agreement. No other investigation or proceeding is pending or threatened against Seller or any Affiliate of Seller, the effect of which would materially and adversely affect Seller's performance of its obligations in this Agreement.

3.2.7 Eligible Contract Participant. Seller, and any guarantor of its obligations under this Agreement, is an "eligible contract participant" as that term is defined in the United States Commodity Exchange Act.

3.2.8 Undertaking of Agreement; Professionals and Experts. Seller has engaged those professional or other experts it believes necessary to understand its rights and obligations pursuant to this Agreement. In entering into this Agreement and agreeing to undertake the obligations within, Seller has investigated and determined that it is capable of performing and has not relied upon the advice, experience or expertise of Utility in connection with the transactions contemplated by this Agreement.

3.2.9 Verification. All information relating to the Facility, its operation and output provided to Utility and contained in this Agreement has been verified by Seller and is true and accurate.

3.2.10 Credit Representations and Warranties.

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Neither Seller nor any of its principal equity owners is or has at any time defaulted in any of its payment obligations for electricity purchased from Utility.

(c) Seller is not in default under any of its other agreements and is current on all financial obligations, including construction related financial obligations.

(d) Seller owns and will continue to own through the Term of this Agreement all right, title, and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

3.2.11 Seller's QF Status. As of the Effective Date and the Commercial Operation Date, the Facility holds QF status.

3.2.12 Seller's Eligibility for a Standard Power Purchase Agreement and Standard Pricing. As of the Effective Date and the Commercial Operation Date, Seller has not made any changes in its ownership, control or management that would cause the Facility to fail to satisfy the eligibility requirements for entering into the standard power purchase agreement or receipt of standard pricing under Utility's Schedule XX, as applicable.

(continued)

3.3 No Other Representations or Warranties. Each Party acknowledges that it has entered into this Agreement in reliance upon only the representations and warranties provided in this Agreement, and that no other representations or warranties have been made by the other Party with respect to the subject matter.

3.4 Continuing Nature of Representations and Warranties; Notice. The representations and warranties provided in this Section 3 are made as of the Effective Date and deemed repeated as of the Commercial Operation Date. If at any time during the Term, either Party obtains actual knowledge of any event or information that would have caused any of the representations and warranties in this Agreement to be materially untrue or misleading at the time given, such Party must provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required by this section must be given as soon as practicable after the occurrence of each such event.

SECTION 4
DELIVERIES OF NET OUTPUT

4.1 Purchase and Sale. Subject to the provisions of this Agreement, Seller must sell and make available to Utility, and Utility must purchase and receive the entire Net Output from the Facility at the Point of Delivery; provided that in no event will Seller deliver any amount of Net Output in excess of the Maximum Delivery Rate in violation of Seller's Generation Interconnection Agreement or in excess of the transmission service allocated to Facility as a Network Resource by Utility Transmission. Seller will defend, indemnify, and hold Utility harmless from and against any and all losses and penalties Utility incurs as a result of Seller's violation of this Section 4.1, as provided in Section 6.2. Utility is under no obligation to make any purchase other than Net Output and is not obligated to purchase, receive, or pay for Net Output that is not delivered to the Point of Delivery.

4.2 Designation as Network Resource.

(a) Within fifteen (15) Business Days following the Effective Date, or, in the event the Facility is an On-system QF and there is no interconnection study for the Facility as of the Effective Date, within fifteen (15) days of the date Seller delivers Utility a copy of the interconnection study, Utility will submit an application to Utility Transmission requesting designation of the Facility as a Network Resource, effective as of ninety (90) days before the Scheduled Commercial Operation Date or as soon as practicable after the Effective Date of the Agreement if the Scheduled Commercial Operation Date occurs less than ninety (90) days following the Effective Date, thereby, in either case, authorizing transmission service under Utility's Network Integration Transmission Service Agreement with Utility Transmission. Utility Transmission may respond that the designation is granted without a study or may require a study to be performed.

(b) If the Facility is an Off-System QF and Utility Transmission requires a study to be performed, Utility will notify Seller of the results of the study within five (5) Business Days after Utility's receipt of the results from Utility Transmission. If Utility is notified in writing by Utility Transmission that designation of the Off-System QF as a Network Resource requires the construction of network upgrades or otherwise requires potential redispatch of other Network Resources of Utility (the "Conditional DNR Notice"), within fifteen (15) Business Days after receiving the Conditional DNR Notice, Utility will notify Seller whether Utility has determined that associated costs should be allocated to Seller and, if so, the amount of the costs ("Cost Allocation Notice"). Seller must notify

(continued)

Utility within fifteen (15) Business Days of receiving the Cost Allocation Notice if it objects to the allocation of the costs in the Cost Allocation Notice ("Cost Allocation Objection Notice").

(c) If Utility timely receives a Cost Allocation Objection Notice under Section 4.2(b), Utility shall initiate a proceeding with the Commission within fifteen (15) Business Days of its receipt of the Cost Allocation Objection Notice by filing its proposed cost allocation determination. The Parties reserve the right to present their respective positions to the Commission as to whether and how the Contract Price or other non-rate terms and conditions of this Agreement should be adjusted in light of the Conditional DNR Notice.

(d) Any time between Seller's receipt of the Cost Allocation Notice and the last day of the fifteen (15)-day period after the Commission issues an order allocating costs of transmission service network upgrades in whole or in part to Seller, by written notice to Utility, Seller may terminate this Agreement or, subject to the requirements of OAR 860-029-0044 and Schedule XX, designate an alternate Point of Delivery that is acceptable to Utility upon written notice to Utility. Termination by Seller under this Section 4.2(d) will not be an Event of Default and no damages or other liabilities under this Agreement will be owed by one Party to the other Party; provided, however, that Seller's right to terminate the Agreement under this Section 4.2(d) will cease following (a) any amendment of this Agreement associated with addressing matters covered under this Section 4.2 or (b) Utility incurring costs at Seller's request in furtherance of addressing matters covered under this Section 4.2. In the event the Parties agree to amend the Agreement to address an agreed-upon cost allocation or there is an order by the Commission allocating costs of transmission service network upgrades, if this Agreement is not terminated, the Scheduled Commercial Operation Date will be extended on a day-for-day basis for each day that occurs from the date of the Cost Allocation Notice and the earlier of the date of any such amendment or date of issuance of an order by the Commission.

4.3 No Sales to Third Parties. During the Term, Seller will not sell any Net Output, energy, Capacity Rights, Ancillary Services or Environmental Attributes from the Facility to any party other than Utility; provided, however, that this restriction does not apply during periods when Utility is in default under this Agreement because it has failed to accept or purchase Net Output as required under this Agreement or, with respect to Environmental Attributes, to the extent title to such Environmental Attributes does not pass to Utility under this Agreement.

4.4 Title and Risk of Loss of Net Output. Seller must deliver Net Output to the Point of Delivery and Capacity Rights free and clear of all liens, claims, and encumbrances. Title to and risk of loss of all Net Output transfers from Seller to Utility upon its delivery to Utility at the Point of Delivery. Seller is in exclusive control of, and responsible for, any damage or injury caused by, all Output up to and at the Point of Delivery. Utility is in exclusive control of, and responsible for, any damages or injury caused by, Net Output after the Point of Delivery.

4.5 Curtailment. Utility is not obligated to purchase, receive, pay for, or pay any damages associated with Net Output not delivered to the Point of Delivery due to any of the following: (a) the interconnection between the Facility and the System is disconnected, suspended or interrupted, in whole or in part, consistent with the terms of the Generation Interconnection Agreement; (b) the Market Operator or Transmission Provider directs a general curtailment, reduction, or redispatch of generation in the area (which would include the Net Output) for any reason required or permitted under applicable Federal laws and regulations, NERC standards or directives, and/or tariffs of the Market Operator, Transmission Provider, or Interconnection Provider, even if and no matter how such curtailment or redispatch directive

(continued)

is carried out by Utility, which may fulfill such directive by acting in its sole discretion; or if Utility curtails or otherwise reduces the Net Output in any way in order to meet its obligations to the Market Operator or Transmission Provider to operate within System limitations; (c) the Facility's Output is not received because the Facility is not fully integrated or synchronized with the System; or (d) an event of Force Majeure prevents either Party from delivering or receiving Net Output. Seller will reasonably determine the MWh amount of Net Output curtailed under this Section 4.5 based on the amount of energy that could have been generated at the Facility and delivered to Utility as Net Output but that was not generated and delivered because of the curtailment. Seller must promptly provide Utility with access to such information and data as Utility may reasonably require to confirm to its reasonable satisfaction the amount of energy that was not generated or delivered because of a curtailment described in this Section 4.5.

4.6 Utility as Merchant or Otherwise as Purchaser. Seller acknowledges that Utility, acting in its merchant capacity function or otherwise as purchaser under this Agreement, has no responsibility for or control over Utility Transmission, in either its capacity as Transmission Provider or Interconnection Provider, as applicable, consistent with the FERC Standards of Conduct, 18 CFR Part 358. Notwithstanding the foregoing, it is understood and agreed that to the extent Utility has any rights or claims against Utility Transmission under the Network Integration Transmission Services Agreement and/or the Tariff with respect to any actual or alleged breach by Utility Transmission of its duties and obligations thereunder, e.g., in connection with a wrongful curtailment, etc., upon written notice from Seller that such breach adversely impacts Seller, Utility will take appropriate action and make good faith efforts to pursue applicable remedies on Seller's behalf.

4.7 Ownership of Environmental Attributes; RPS Certification.

(a) If the Contract Price is based on Standard Fixed Pricing, the Seller shall own any Environmental Attributes associated with the Output of the Facility;

(b) If the Contract Price is based on Renewable Fixed Pricing, (i) Seller shall own all Environmental Attributes associated with the Output of the Facility during the Renewable Resource Sufficiency Period; and (ii) Utility shall own all Environmental Attributes associated with the Output of the Facility during the Renewal Resource Deficiency Period and, in such case, Seller must transfer to Utility at no further cost the Environmental Attributes, including renewable energy credits, associated with the Output of the Facility.

(c) Seller represents, warrants, and covenants that, as of the Commercial Operation Date and continuously thereafter during the Term, Seller has obtained and will continue to maintain RPS certification from the Oregon Department of Energy with respect to the Output of the Facility.

4.8 Purchase and Sale of Capacity Rights; Ancillary Services. Seller transfers to Utility, and Utility accepts from Seller, any right, title, and interest that Seller may have in and to Capacity Rights, if any, and Ancillary Services, if any, existing during the Term, with respect to the Net Output. Seller represents that it has not sold, and covenants that during the Term it will not sell or attempt to sell to any other person or entity the Capacity Rights, if any, and Ancillary Services, if any. During the Term, Seller must not report to any person or entity that the Capacity Rights, if any, and Ancillary Services, if any belong to anyone other than Utility. At Utility's request, Seller must execute such documents and instruments as may be reasonably required to effect recognition and transfer of the Net Output or any Capacity Rights or Ancillary Services to Utility.

(continued)

SECTION 5
CONTRACT PRICE; COSTS

5.1 Contract Price; Includes Capacity Rights. Except as may be provided otherwise in this Agreement including as set forth in Exhibit L if applicable, Utility will pay Seller the Contract Price for all deliveries of Net Output and Capacity Rights, up to the Maximum Delivery Rate. Utility is not required to purchase any Net Output above the Maximum Delivery Rate.

5.1.1 Deliveries Prior to the Commercial Operation Date. Beginning no earlier than ninety (90) days before the Scheduled Commercial Operation Date, Utility will pay Seller for Net Output delivered at the Point of Delivery before the Commercial Operation Date, an amount per MWh equal to the lower of (i) eighty five percent (85%) of the Firm Electric Market Pricing for the applicable hour on the applicable day in the applicable month; and (ii) eighty five percent (85%) of the Contract Price; provided, however, that Seller's right to receive payment for energy deliveries under this Section 5.1.1 is subject to Utility's right of offset under Section 10.2 for, among other things, payment by Seller of any Delay Damages owed to Utility by Seller. Notwithstanding the foregoing, if Utility, in exercising commercially reasonable efforts, is able to accept deliveries of Net Output earlier than ninety (90) days before the Scheduled Commercial Operation Date, Utility will pay Seller for Net Output delivered at the Point of Delivery under this Section 5.1.1; provided that under no circumstances shall Utility be obligated to accept deliveries of Net Output earlier than 180 days before the Scheduled Commercial Operation Date.

5.1.2 Commercial Operation. For the period beginning on the Commercial Operation Date and thereafter during the Term, Utility will pay to Seller the Contract Price per MWh of Net Output delivered to the Point of Delivery. The Contract Price will not be adjusted if Schedule XX is modified during the Term of this Agreement. If Utility requests a modification to Schedule XX, including a modification to pricing, neither Seller nor Utility will request that any change in Schedule XX be applicable to this Agreement.

5.2 Costs and Charges. Seller shall be responsible for paying or satisfying when due all costs or charges imposed in connection with the scheduling and delivery of Net Output up to and at the Point of Delivery, including (a) transmission costs, transmission line losses and any costs or charges (including imbalance charges and penalties) imposed in connection with scheduling and delivery of Net Output up to and at the Point of Delivery and (b) transmission costs, transmission line losses, and any operation and maintenance charges imposed by Interconnection Provider or Transmission Provider in connection with scheduling and delivery of Net Output up to and at the Point of Delivery. Except as determined otherwise under Section 4.2, Utility shall be responsible for all costs or charges, including transmission costs, transmission line losses and any costs or charges imposed in connection with the receipt of Net Output at the Point of Delivery and the scheduling and delivery of Net Output from the Point of Delivery, other than such costs or charges that are caused by Seller's acts or omissions in breach of this Agreement. Without limiting the generality of the foregoing, Seller, in accordance with the Generation Interconnection Agreement, shall be responsible for all costs and expenses associated with modifications to the Interconnection Facilities or the System (including System upgrades) caused by or related to the Facility, including all costs and expenses associated with the interconnection of the Facility with the System.

5.3 Station Service. Seller is responsible for arranging and obtaining, at its sole risk and expense, station service required for the Facility.

5.4 Taxes. Seller must pay, or reimburse Utility for, all existing and any new sales, use, excise, severance, ad valorem, and any other similar taxes, imposed or levied by any Governmental Authority on the Net Output or Capacity Rights up to and including the Point of Delivery, regardless of whether such

(continued)

taxes are imposed on Utility or Seller under Requirements of Law. Utility must pay, or reimburse Seller for, all such taxes imposed or levied by any Governmental Authority on the Net Output or Capacity Rights beyond the Point of Delivery, regardless of whether such taxes are imposed on Utility or Seller under Requirements of Law. The Contract Price will not be adjusted on the basis of any action of any Governmental Authority with respect to changes to or revocations of sales and use tax benefits, rebates, exception or give back. In the event any taxes are imposed on a Party for which the other Party is responsible in this Agreement, the Party on which the taxes are imposed must promptly provide the other Party notice and such other information as such Party reasonably requests with respect to any such taxes.

5.5 Costs of Ownership and Operation. Without limiting the generality of any other provision of this Agreement and subject to Section 5.4, Seller is solely responsible for paying when due (a) all costs of owning and operating the Facility in compliance with existing and future Requirements of Law and the terms and conditions of this Agreement, and (b) all taxes and charges (however characterized) now existing or later imposed on or with respect to the Facility and its operation, including any tax or charge (however characterized) payable by a generator of Environmental Attributes.

5.6 Rates Not Subject to Review. The rates for service specified in this Agreement will remain in effect until expiration of the Term, and are not subject to change for any reason, including regulatory review, absent agreement of the Parties or as determined under Section 4.2. Neither Party will petition FERC to amend such prices or terms or support a petition by any other person seeking to amend such prices or terms, absent the agreement in writing of the other Party. Further, absent the agreement in writing by both Parties, the standard of review for changes to this Agreement proposed by a Party, a non-party or FERC acting sua sponte will be the “public interest” application of the “just and reasonable” standard of review as described in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and clarified by *Morgan Stanley Capital Group. Inc. v. Public Util. Dist. No. 1 of Snohomish*, 554 U.S. 527, 128 S. Ct. 2733 (2008).

5.7 Participation in an RTO. If, after the Effective Date, Utility joins an RTO, then the Parties shall negotiate in good faith any such amendments to this Agreement that may be necessary as a result of such RTO membership.

SECTION 6
OPERATION AND CONTROL

6.1 As-Built Supplement; Modifications to Facility. No later than ninety (90) days following the Commercial Operation Date, Seller must provide Utility the As-Built Supplement which will be incorporated into Exhibits B and C of this Agreement. Except with Utility’s prior written consent or as permitted under and subject to the requirements of Section 6.8, the Facility, as reflected in the As-Built Supplement to be provided under this Section or subsequently during the Term, may not (a) have a Nameplate Capacity Rating that exceeds that stated in Exhibit B, or (b) result in the expected annual Net Output, as calculated in Exhibit A, increasing by more than ten percent (10%), except to the extent Seller complies with the requirements of Section 6.8.3.

6.2 Standard of Facility Construction and Operation.

6.2.1 General. Seller will construct and operate all interconnected equipment associated with the Facility within its control in accordance with all applicable federal, state, and local laws and regulations to

(continued)

ensure system safety and reliability of interconnected operations. At Seller's sole cost and expense, Seller must operate, maintain, and repair the Facility in accordance with (a) the applicable and mandatory standards, criteria, and formal guidelines of FERC, NERC, any RTO, and any other Electric System Authority and any successors to the functions thereof; (b) the Permits and Required Facility Documents; (c) the Generation Interconnection Agreement; (d) all Requirements of Law; (e) the requirements of this Agreement; and (f) Prudent Electrical Practice. Except for any claims Seller may have in connection with Utility's obligation under Section 4.6 acting in its merchant function capacity or otherwise as purchaser to take appropriate action and make good faith efforts to pursue applicable remedies on Seller's behalf, Seller acknowledges that it has no claim under this Agreement against Utility acting as in its capacity Transmission Provider or Interconnection Provider or with respect to the provision of station service.

6.2.2 Qualified Operator. Seller or an Affiliate of Seller must operate and maintain the Facility or cause the Facility to be operated and maintained by an entity (i) that has at least two (2) years of experience in the operation and maintenance of similar facilities of comparable size to the Facility; or (ii) that Seller demonstrates is otherwise qualified to operate the Facility in a manner consistent with Prudent Electrical Practices and has the financial resources and qualified personnel necessary to fulfill obligations under this Agreement. Seller must provide Utility thirty (30) days prior written notice of any change in operator of the Facility.

6.2.3 Fines and Penalties.

(a) Without limiting a Party's rights under Section 6.2.3(b), each Party must pay all fines and penalties incurred by such Party on account of noncompliance by such Party with Requirements of Law as such fines and penalties relate to the subject matter of this Agreement, except where such fines and penalties are being contested in good faith through appropriate proceedings.

(b) If fines, penalties, or legal costs are assessed against or incurred by either Party (the "Indemnified Party") on account of any action by any Governmental Authority due to noncompliance by the other Party (the "Indemnifying Party") with any Requirements of Law or the provisions of this Agreement, or if the performance of the Indemnifying Party is delayed or stopped by order of any Governmental Authority due to the Indemnifying Party's noncompliance with any Requirements of Law, the Indemnifying Party must indemnify and hold harmless the Indemnified Party against any and all Liabilities suffered or incurred by the Indemnified Party as a result thereof. Without limiting the generality of the foregoing, the Indemnifying Party must reimburse the Indemnified Party for all fees, damages, or penalties imposed on the Indemnified Party by any Governmental Authority, other person or to other utilities for violations to the extent caused by a default by the Indemnifying Party or a failure of performance by the Indemnifying Party under this Agreement.

6.3 Interconnection. Seller is responsible for the costs and expenses associated with obtaining from the Interconnection Provider network resource interconnection service for the Facility at its Nameplate Capacity Rating. Seller has no claims under this Agreement against Utility, acting in its merchant function capacity or otherwise as purchaser, with respect to any requirements imposed by or damages caused by (or allegedly caused by) acts or omissions of the Transmission Provider or Interconnection Provider, acting in such capacities, in connection with the Generation Interconnection Agreement or otherwise.

6.4 Coordination with System. Seller's delivery of electricity to Utility under this Agreement must be at a voltage, phase, power factor, and frequency as reasonably specified by Utility. Seller will furnish, install, operate, and maintain in good order and repair, and without cost to Utility, such switching

(continued)

equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus determined by Utility to be reasonably necessary for the safe and reliable operation of the Facility in parallel with the System, or Seller may contract with Utility to do so at the Seller's expense. Utility must at all times have access to all switching equipment capable of isolating the Facility from the System.

6.5 Outages.

6.5.1 Planned Outages. Seller must provide Utility with an annual forecast of Planned Outages for each Contract Year at least one (1) month, but no more than three (3) months, before the first (1st) day of that Contract Year, specifying the applicable number of Off-Peak Hours and On-Peak Hours. Seller may update such Planned Outage schedule as necessary to comply with Prudent Electrical Practices. Although the Planned Outage schedule should include predetermined outage duration, the outage may be extended when the original scope of work requires more time than originally scheduled, subject to notice of at least five (5) days to Utility when feasible. Except as may be required in the Generation Interconnection Agreement, Seller may not schedule a Planned Outage during any portion of the months of [December and July[19]], except to the extent reasonably required to enable a vendor to satisfy a guarantee requirement. With twelve (12) months prior notice before the start of any Contract Year, Utility may change these months.

6.5.2 Maintenance Outages. If Seller reasonably determines that it is necessary to schedule a Maintenance Outage, Seller must notify Utility of the proposed Maintenance Outage as soon as practicable but in any event at least five (5) days before the outage begins. Although the notice of a Maintenance Outage must include an expected completion date and time of the outage, the outage may be extended when the original scope of work requires more time than originally scheduled, subject to notice of at least five (5) days to Utility when feasible. Seller must take all reasonable measures consistent with Prudent Electrical Practices to not schedule any Maintenance Outage during the months of [December and July[20]]; provided that with twelve (12) months prior notice before the start of any Contract Year, Utility may change these months. Notice of a proposed Maintenance Outage by Seller must include the expected start date and time of the outage, the amount of generation capacity of the Facility that will not be available, and the expected completion date and time of the outage. Utility will promptly respond to such notice and may request reasonable modifications in the schedule for the outage. Seller must use all reasonable efforts to comply with any request to modify the schedule for a Maintenance Outage provided that such change has no substantial impact on Seller. Once the Maintenance Outage has commenced, Seller must keep Utility apprised of any changes in the generation capacity available from the Facility during the Maintenance Outage and any changes in the expected Maintenance Outage completion date and time. As soon as practicable, any notifications given orally or by email must be confirmed in writing. Seller must take all reasonable measures consistent with Prudent Electrical Practices to minimize the frequency and duration of Maintenance Outages.

6.5.3 Forced Outages. Seller must promptly provide to Utility an oral report, via telephone to a number specified by Utility (or other method approved by Utility), of any Forced Outage resulting in more than ten percent (10%) of the Nameplate Capacity Rating of the Facility being unavailable. This report from Seller must include the amount of the generation capacity of the Facility that will not be available because of the Forced Outage and the expected return date of such generation capacity. Seller must promptly update

[19] **Note to Form –** Each utility will identify the two applicable months.

[20] **Note to Form –** Each utility will identify the two applicable months.

(continued)

the report as necessary to advise Utility of changed circumstances. As soon as practicable, the oral report must be confirmed in writing to Utility. Seller must take all reasonable measures consistent with Prudent Electrical Practices to avoid Forced Outages and to minimize their duration.

6.5.4 Notice of Deratings and Outages. Without limiting the foregoing, Seller will inform Utility, via telephone to a number specified by Utility (or other method approved by Utility), of any limitations, restrictions, deratings, or outages reasonably predicted by Seller to affect more than five percent (5%) of the Nameplate Capacity Rating of the Facility for the following day and will promptly update such notice to the extent of any material changes in this information.

6.5.5 Effect of Outages on Estimated Output. Seller represents and warrants that the Expected Monthly Net Output provided in Exhibit A takes into account the Planned Outages, Maintenance Outages, and Forced Outages that Seller reasonably expects to encounter in the ordinary course of operating the Facility.

6.6 Scheduling.

6.6.1 Cooperation and Standards. With respect to any and all scheduling requirements, (a) Seller must cooperate with Utility with respect to scheduling Net Output, and (b) each Party will designate authorized representatives to communicate regarding scheduling and related matters arising under this Agreement. Each Party must comply with the applicable variable resource standards and criteria of any applicable Electric System Authority, as applicable.

6.6.2 Schedule Coordination. If, as a result of this Agreement, Utility is deemed by an RTO to be financially responsible for Seller's performance under the Generation Interconnection Agreement due to Seller's lack of standing as a "scheduling coordinator" or other RTO-recognized designation, qualification or otherwise, then Seller must promptly take all actions necessary to acquire such RTO-recognized standing (or must contract with a third party who has such RTO-recognized standing) so that Utility is no longer responsible for Seller's performance under the Generation Interconnection Agreement or RTO requirement.

6.7 Forecasting.

6.7.1 Long-Range Forecasts. Seller must, by [December 1st[21]] of each year during the Term (except for the last year of the Term), provide an annual update to the expected long-term monthly/diurnal mean net energy and net capacity factor estimates (12 X 24 profile). Seller must prepare such forecasts utilizing a renewable energy resource prediction model or service that is satisfactory to Utility in the exercise of its reasonable discretion and comparable in accuracy to models or services commonly used in the industry that reflects updated assumptions relative to the applicable forecast period. The forecasts provided by Seller must comply with all applicable Electric System Authority tariff procedures, protocols, rules, and testing as necessary and as may be modified from time to time.

6.7.2 Day-Ahead Forecasts, Real-Time Forecasting and Updates. At Seller's expense, Utility will either directly provide or solicit and obtain from a qualified renewable energy production forecasting vendor forecast data and information with respect to the Facility, including day-ahead and real-time forecasting services and provision of real-time meteorological data necessary for compliance with

[21] **Note to Form** – Each utility will identify the applicable date.

(continued)

applicable Electric System Authority procedures, protocols, rules, and testing. Upon request by Utility, Seller must provide a 24-hour telephone number that Utility may contact to determine the then-current status of the Facility. Utility will present Seller with an invoice for the costs of providing or obtaining, as applicable, such forecasting data. Seller must pay the amount stated on the invoice within fifteen (15) days of receipt. Utility reserves the right to change its pricing, if providing the services directly, or the forecasting vendor, as applicable, in its sole discretion during the Term.[22]

6.8 Increase in Nameplate Capacity Rating; Expansion or New Project; Allowable Facility Upgrades.

6.8.1 No Increase to Nameplate Capacity Rating. During the term of this Agreement, Seller may not (i) increase the Nameplate Capacity Rating of the Facility or cause the Facility to deliver Net Output in quantities in excess of the Maximum Delivery Rate; or (ii) except to the extent Seller complies with the requirements of Section 6.8.3, increase the Expected Net Output of the Facility, as calculated in Exhibit A, by more than ten percent (10%); in either case, through any means, including replacement or modification of Facility equipment or related infrastructure.

6.8.2 Expansion or New Project. If Seller elects to build an expansion or additional project such that the Facility and the expansion or additional project would be deemed a single QF or the same site under Commission or FERC regulations, Seller may not require Utility to purchase (and Utility will have no obligation to purchase pursuant to this Agreement) the output of any such expansion or additional facility under the terms, conditions, and prices in this Agreement, but Seller may exercise any rights to enter into a new agreement for the sale of such incremental energy from such expansion or additional facility that is a QF under then-applicable laws and regulations. Seller agrees that it will not seek to avoid the obligations in this Section 6.8 through use or establishment of a special purpose entity or other Affiliate. Any such expansion or additional facility may not materially and adversely impact the ability of either Party to fulfill its obligations under this Agreement.

6.8.3 Allowable Upgrades. In the event that Seller seeks to upgrade the Facility in a manner that does not increase the Nameplate Capacity Rating of the Facility, but which is reasonably likely to cause the Expected Net Output to exceed that listed in Exhibit A by more than ten percent (10%), such upgrades may only be made subject to the following requirements:

(a) The proposed upgrades must not cause Seller to fail to meet the current eligibility requirements for either the standard power purchase agreement or standard prices, to breach its Generation Interconnection Agreement, or necessitate Network Upgrades in order to maintain designated network status.

(b) At least six (6) months in advance of the scheduled installation date for the proposed upgrades, Seller must send written notice to Utility containing a detailed description of the proposed upgrades and their impact on Expected Net Output and a revised 12 x 24 delivery schedule and requesting indicative pricing for the incremental additional Net Output expected to be generated as a result of the upgrades.

[22] **Note to Form** – The language in the above Section 6.7.2 applies only to wind, solar (including solar plus battery storage) and hydro QFs. For any other QF, this provision will be replaced with a provision requiring Seller to provide a monthly delivery schedule that sets forth the expected hourly delivery rate for each day of such month.

(continued)

(c) Within thirty (30) days after receiving such a request, Utility must respond with indicative pricing for the expected incremental additional Net Output to be generated as a result of the upgrades in excess of ten percent (10%) of the Expected Net Output specified in Exhibit A.

(d) Within thirty (30) days after receiving indicative pricing, Seller may request a draft amendment to this Agreement to reflect revised pricing for the remainder of the term, effective upon completion of the upgrades. If it is not reasonably feasible to separately meter the incremental additional Net Output resulting from the proposed upgrades, Utility may create a blended rate based on the proportion the expected incremental additional Net Output bears to the expected total Net Output following the installation of the upgrades.

Within ninety (90) days after the date on which upgrades are installed under subsections (a), (b), or (c) of this Section 6.8.3, Seller is obligated to provide Utility with an As-Built Supplement describing in detail Facility, as modified by the allowable upgrades, which As-Built Supplement will be incorporated into Exhibits B and C of this Agreement.

If Seller wishes to install upgrades that would cause the Facility to increase its Nameplate Capacity Rating, Seller may elect to terminate the Agreement and may choose to enter a new standard or new non-standard power purchase agreement, based on applicable eligibility requirements, at the then-current avoided cost pricing; provided that such termination of this Agreement will be treated as a termination for a Seller Event of Default for which Seller will owe Utility termination damages. In such case, notwithstanding any other provision in this Agreement to the contrary, with respect to any portion of the period in which Seller owes Utility termination damages in which Seller is contractually obligated to deliver output under the new agreement, the Cost to Cover will be calculated based on the pricing set forth in the new agreement.

6.9 Telemetering. Seller must provide telemetering equipment and facilities capable of transmitting the following information concerning the Facility pursuant to the Generation Interconnection Agreement and to Utility on a real-time basis, and will operate such equipment when requested by Utility to indicate:

(a) instantaneous MW output at the Point of Delivery;

(b) Net Output; and

(c) the Facility’s total instantaneous generation capacity.

Commencing on the date of initial deliveries under this Agreement, Seller must also transmit or otherwise make accessible to Utility any other data from the Facility that Seller receives on a real time basis, including Net Output data. Such real time data must be made available to Utility on the same basis as Seller receives the data (e.g., if Seller receives the data in four second intervals, Utility must also receive the data in four second intervals). If Seller uses a web-based performance monitoring system for the Facility, Seller must provide Utility access to Seller’s web-based performance monitoring system.

6.10 Transmission Provider Consent. Within ten (10) days of the Effective Date, Seller must execute and submit to Utility, a consent in the form provided in Exhibit G or as otherwise required by Transmission Provider, that allows Utility to read the meter and receive any and all data from the Transmission Provider relating to transmission of Output or other matters relating to the Facility without the need for further consent from Seller.

(continued)

6.11 Dedicated Communication Circuit. Seller must install a dedicated direct communication circuit (which may be by common carrier telephone) between Utility and the control center in the Facility's control room or such other communication equipment as the Parties may agree.

6.12 Reports and Records.

6.12.1 Electronic Fault Log. Seller must maintain an electronic fault log of operations of the Facility during each hour of each month of the Term commencing on the Effective Date. Seller must provide Utility with a copy of the any monthly fault log promptly upon Utility's request and shall provide Utility with all twelve (12) monthly electronic fault logs for each Contract Year within thirty (30) days after the end of the applicable Contract Year to which the fault log applies. The fault log must be sufficiently detailed to enable Utility to calculate the Performance Guarantee and in such electronic form as is acceptable to Utility.

6.12.2 Other Information to be Provided to Utility. Following the Effective Date until the Commercial Operation Date, Seller must provide to Utility a quarterly progress report stating the percentage completion of the Facility and a brief summary of construction activity during the prior quarter and contemplated for the next calendar quarter.

6.12.3 Information to Governmental Authorities. Seller must, promptly upon written request from Utility, provide Utility with data collected by Seller related to the construction, operation or maintenance of the Facility reasonably required for reports to any Governmental Authority or Electric System Authority, along with a statement from an officer of Seller certifying that the contents of the submittals are true and accurate to the best of Seller's knowledge. Seller must use best efforts to provide this information to Utility sufficiently in advance to enable Utility to review such information and meet any submission deadlines. Utility will reimburse Seller for all of Seller's reasonable actual costs and expenses in excess of $5,000 per year, if any, incurred in connection with Utility's requests for information under this Section 6.12.3.

6.12.4 Data Request. Seller must, promptly upon written request from Utility, provide Utility with data collected by Seller related to the construction, operation or maintenance of the Facility reasonably required for information requests from any Governmental Authorities, state or federal agency intervener or any other party achieving intervenor status in any Utility rate proceeding or other proceeding before any Governmental Authority. Seller must use best efforts to provide this information to Utility sufficiently in advance to enable Utility to review such data and meet any submission deadlines. Utility will reimburse Seller for all of Seller's reasonable actual costs and expenses in excess of $5,000 per year, if any, incurred in connection with Utility's requests for information under this Section 6.12.4.

6.12.5 Documents to Governmental Authorities. After sending or filing any statement, application, and report or any document with any Governmental Authority or Electric System Authority relating to operation and maintenance of the Facility, Seller must promptly provide to Utility a copy of the same.

6.12.6 Notice of Material Adverse Events. Seller must promptly notify Utility of receipt of written notice or actual knowledge by Seller or its Affiliates of the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility, or Seller's ability to develop, construct, operate, maintain or own the Facility, including any material violation of any environmental laws or regulations arising out of the construction or operation of the Facility, or the presence of Environmental Contamination at the Facility or on the Premises.

(continued)

6.12.7 Notice of Litigation. Following its receipt of written notice or knowledge of the commencement of any action, suit, or proceeding before any court or Governmental Authority against Seller, its members, or any Affiliate relating to the Facility or this Agreement, or that could materially and adversely affect Seller's performance of its obligations in this Agreement, Seller must promptly notify Utility.

6.12.8 Additional Information. Seller must provide to Utility such other information as relevant to Seller's performance of its obligations under this Agreement or the Facility as Utility may, from time to time, reasonably request.

6.12.9 Confidential Treatment. The reports and other information provided to Utility under this Section 6.12 will be treated as confidential for a period of two (2) years if such treatment is requested in writing by Seller at the time the information is provided to Utility, subject to Utility's rights to disclose such information pursuant to Sections 6.12.3 and 6.12.4, and pursuant to any applicable Requirements of Law. Seller will have the right to seek confidential treatment of any such information from any Governmental Authority entitled to receive such information.

6.13 Financial and Accounting Information. If Utility or one of its Affiliates determines that, under (a) the Accounting Standards Codification ("ASC") 810, Consolidation of Variable Interest Entities, and (b) Requirements of Law that it may hold a variable interest in Seller, but it lacks the information necessary to make a definitive conclusion, Seller agrees to provide, upon Utility's written request, sufficient financial and ownership information so that Utility or its Affiliate may confirm whether a variable interest does exist under ASC 810 and Requirements of Law. If Utility or its Affiliate determines that, under ASC 810, it holds a variable interest in Seller, Seller agrees to provide, upon Utility's written request, sufficient financial and other information to Utility or its Affiliate so that Utility may properly consolidate the entity in which it holds the variable interest or present the disclosures required by ASC 810 and Requirements of Law. Utility will reimburse Seller for Seller's reasonable costs and expenses, if any, incurred in connection with Utility's requests for information under this Section 6.13. Seller will have the right to seek confidential treatment of any such information from any Governmental Authority entitled to receive such information.

6.14 Access Rights. Upon reasonable prior notice and subject to compliance with all written health, safety and security requirements of Seller provided to Utility, and Requirements of Law relating to workplace health and safety, and not interfering with Seller's maintenance or operation of the Facility, Seller must provide Utility and its employees, agents, inspectors and representatives ("Utility Representatives") with reasonable access to the Facility: (a) for the purpose of witnessing the inspection and testing of metering equipment and remote sensing devices; (b) as necessary to witness any acceptance tests; (c) as necessary to witness any testing associated with the Facility, including testing with respect to the Performance Guarantee; and (d) for other reasonable purposes at the reasonable request of Utility. Utility will release Seller and its employees, agents and representatives from and indemnify Seller and its employees, agents and representatives against any and all Liabilities resulting from actions or omissions by any of the Utility Representatives in connection with their access to the Facility (whether pursuant to this Section 6.14 or otherwise), except to the extent such Liabilities are caused by the intentional or negligent act or omission of Seller or its Affiliates or their respective employees, agents and representatives.

6.15 Performance Guarantee. Seller is subject to the terms and conditions set forth in the

(continued)

Performance Guarantee attached as Exhibit F ("Performance Guarantee").[23]

SECTION 7
QUALIFYING FACILITY STATUS; ELIGIBILITY FOR STANDARD PRICING

7.1 Seller's QF Status. Seller must maintain throughout the Term the Facility's status as a QF. Seller must provide Utility with copies of any QF certification or recertification documentation within ten (10) days of its filing with any Governmental Authority. At any time during the Term, Utility may require Seller to provide Utility with evidence satisfactory to Utility in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.

7.2 Seller's Eligibility for a Standard Power Purchase Agreement and Standard Pricing. Seller will not make any changes in its ownership, control or management that would cause the Facility to fail to satisfy the eligibility requirements for entering into the standard power purchase agreement or receipt of standard pricing under Utility's Schedule XX. At Utility's request, but no more than once every twenty-four (24) months, Seller will provide documentation and information reasonably requested by Utility to establish Seller's continued compliance with eligibility requirements for the standard power purchase agreement and standard pricing, as applicable, under Utility's Schedule XX. Utility will take reasonable steps to maintain the confidentiality of any such documentation and information Seller identifies as confidential, provided that Utility may provide all such information to the Commission in a proceeding before the Commission.

SECTION 8
SECURITY AND CREDIT SUPPORT

8.1 Provision of Security. Seller must provide security as provided below if it does not meet the Credit Requirements at any time during the Term of this Agreement. Unless Seller has posted the security provided for below, Seller must provide Utility on a quarterly basis all financial information requested by Utility that is necessary for Utility to verify the Seller continues to satisfy the Credit Requirements.

8.2 Project Development Security.[24] If Seller does not meet the Credit Requirements as of the Effective Date, Seller must post and maintain Project Development Security in favor of Utility within one hundred and twenty (120) days from the Effective Date. If Utility determines at any time after the Effective Date but before the Facility achieves Commercial Operation that Seller (or its guarantor, if applicable) no longer meets the Credit Requirements, Seller must post and maintain Project Development Security in favor of Utility within thirty (30) days. In either case, the Project Development Security must be in the form of either (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to Utility in its reasonable discretion, (b) a Letter of Credit in favor of Utility, in a form acceptable to Utility in its reasonable discretion, or (c) cash escrow with a Qualified Institution. In the event the Project Development Security is provided by a guarantor, Seller or the entity providing the guaranty must provide within five (5) Business Days from receipt of a written request from Utility all reasonable financial records necessary for Utility to confirm the guarantor satisfies the Credit Requirements. If the Commercial

[23] **Note to Form** – Wind, solar, battery storage, solar + storage, and hydroelectric QFs are subject to a Mechanical Availability Guarantee. Geothermal and biomass QFs are subject to a Minimum Delivery Guarantee.

[24] **Note to Form** – This provision to be deleted in PPA with operational QF.

(continued)

Operation Date occurs after the Scheduled Commercial Operation Date, and Seller has failed to pay any Delay Damages when due under this Agreement, Utility is entitled to draw upon the Project Development Security an amount equal to the Delay Damages until the Project Development Security is exhausted. Utility is also entitled to draw upon the Project Development Security for any other damages it is entitled to under this Agreement. Seller is no longer required to maintain the Project Development Security after the Commercial Operation Date, if no damages are owed to Utility under this Agreement and, if applicable, Default Security has been provided as required under this Agreement. Seller may elect to apply the Project Development Security toward the Default Security required by Section 8.3.

8.3 Default Security. If Seller does not meet the Credit Requirements as of the Commercial Operation Date, on the date specified in Section 2.2, or it is determined at any time after the Facility achieves Commercial Operation that Seller (or its guarantor, if applicable) no longer meets the Credit Requirements, within ten (10) days of notification from Utility, Seller must post and maintain Default Security in favor of Utility in the form of either (a) a guaranty from an entity that satisfies the Credit Requirements, in a form acceptable to Utility in its reasonable discretion, (b) a Letter of Credit in favor of Utility, in a form acceptable to Utility in its reasonable discretion, (c) cash escrow with a Qualified Institution, or (d) a grant of a senior security interest under a security agreement in a form acceptable to Utility in its reasonable discretion. In the event the Default Security is provided in the form of a guaranty, Seller and any entity providing a guaranty, if applicable, must provide within five (5) Business Days from receipt of a written request from Utility all reasonable financial records necessary for Utility to confirm the guarantor satisfies the Credit Requirements. Utility is entitled to draw upon the Default Security for any damages to which it is entitled under this Agreement. If no damages or obligations remain due by Seller to Utility upon termination of the Agreement, Utility must return any remaining Default Security to Seller within sixty (60) days following the termination of the Agreement, then Utility must return any remaining Default Security to Seller within sixty (60) days following the termination of this Agreement.

8.4 No Interest on Security. Except for cash escrow, Seller shall not earn or be entitled to any interest on any Security provided pursuant to this Section 8. Cash escrow will earn interest at the rate the applicable Qualified Institution applies to equivalent money market deposits.

8.5 Grant of Security Interest in Security. To secure its obligations under this Agreement, Seller hereby grants to Utility, as the secured party, a present and continuing security interest in, lien on (and right of setoff against), and assignment of, all Project Development Security or Default Security, as the case may be, posted with Utility in the form of cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Utility. Seller agrees to take such action as Utility reasonably requires in order to perfect a first-priority security interest in, and lien on (and right of setoff against), such performance assurance and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default by Seller, Utility may do any one or more of the following: (a) exercise any of the rights and remedies of a secured party with respect to all the Security, including any such rights and remedies under Requirements of Law then in effect; (b) exercise its right of setoff against any and all property of Seller, as the Defaulting Party, in the possession of Utility or Utility's agent; (c) draw on any outstanding Letter of Credit issued for its benefit; and (d) liquidate all Security then held by or for the benefit of Utility free from any claim or right of any nature whatsoever by Seller, including any equity or right of purchase or redemption by Seller. Utility shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce Seller's obligations under this Agreement (Seller remaining liable for any amounts owing to Utility after such application), subject to Utility's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

(continued)

8.6 Security is Not a Limit on Seller's Liability. The security contemplated under this Section 8 constitutes security for, but is not a limitation of, Seller's obligations and liabilities under this Agreement and is not Utility's exclusive remedy for Seller's failure to perform in accordance with this Agreement. To the extent Utility draws on any Project Development Security or Default Security, Seller must, within fifteen (15) days following such draw, replenish or reinstate the Project Development Security or Default Security, as applicable, to the full amount then required under this Section 8. If any security provided by Seller pursuant to this Section 8 will terminate or expire by its terms within thirty (30) days, and Seller has not delivered to Utility replacement security in such amount and form as is required pursuant to this Section 8, then Utility shall be entitled to draw the full amount of the security and to hold such amount as security until such time as Seller delivers to Utility replacement security in such amount and form as is required pursuant to this Section 8.

SECTION 9
METERING

9.1 Installation of Metering Equipment. At Seller's cost and expense, Seller shall design, furnish, install, own, inspect, test, maintain, and replace all metering equipment as required by the Generation Interconnection Agreement and this Section 9. Seller must use revenue grade metering equipment consistent with American National Standards Institute ("ANSI") standards. In the event Market Operator adopts new meter requirements that are applicable to the Facility, Seller will, at its cost and expense, reasonably cooperate to upgrade any applicable metering equipment. Seller shall reasonably cooperate with Utility in developing any metering protocols necessary for Utility to comply with the requirements of the Market Operator or Utility Transmission.

9.2 Metering. Metering must be performed at the locations specified in Exhibit C and at the locations and in the manner specified in the Generation Interconnection Agreement, and as otherwise may be necessary to perform Seller's obligations under this Agreement. Meters must be capable of recording quantities of Output and Net Output, as the case may be.

9.3 Inspection, Testing, Repair and Replacement of Meters. Utility shall have the right to periodically inspect, test, repair and replace the metering equipment provided for in this Section 9, without Utility assuming any obligations of Seller under this Section 9. If any of the inspections or tests disclose an error exceeding one half of one percent (0.5%), either fast or slow, then the necessary corrections based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, then the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) months, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered. Such correction, when made, shall constitute full adjustment of any claim between Seller and Utility arising out of such inaccuracy of the metering equipment. Nothing in this Agreement shall give rise to Utility, acting in its merchant function capacity or otherwise as purchaser hereunder, having any obligations to Seller, or any other Person, pursuant to or under the Generation Interconnection Agreement.

9.4 Metering Costs. To the extent not otherwise provided in the Generation Interconnection Agreement, Seller shall be responsible for all costs and expenses relating to all metering equipment installed to accommodate Seller's Facility. The actual expense of any Utility-requested additional inspection or testing shall be borne by Utility, unless upon additional inspection or testing the metering

(continued)

equipment is found to register inaccurately by more than the allowable limits established in Section 9.3, in which event the expense of the requested additional inspection or testing shall be borne by Seller.

9.5 SQMD Plan. Prior to commencing Commercial Operation, Seller shall support and reasonably cooperate with Utility in Utility's development and submittal to the Market Operator of its Settlement Quality Meter Data ("SQMD") compliance plan for the Facility. The SQMD compliance plan will detail the metering equipment and any calculation or data validation performed as a part of the data submission process to the Market Operator, consistent with the Market Operator's requirements in the then-current version of the "Business Practice Manual for Metering."

9.6 WREGIS Metering. If Utility owns Environmental Attributes pursuant to Section 4.7, Seller must cause the Facility to implement all necessary generation information communications in WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter dedicated to the Facility and only the Facility.

SECTION 10
BILLINGS, COMPUTATIONS AND PAYMENTS

10.1 Monthly Invoices. On or before the tenth (10th) day following the end of each calendar month, Seller must deliver to Utility an invoice showing Seller's computation of Net Output delivered to the Point of Delivery during such month. When calculating the invoice, Seller must provide computations showing the portion of Net Output that was delivered during On-Peak Hours and the portion of Net Output that was delivered during Off-Peak Hours. If such invoice is delivered by Seller to Utility, then Utility must send to Seller, on or before the later of the twentieth (20th) day following receipt of such invoice or the thirtieth (30th) day following the end of each month, payment for Seller's deliveries of Net Output to Utility.

10.2 Offsets. Either Party may offset any payment due under this Agreement against amounts owed by the other Party pursuant under this Agreement. Either Party's exercise of recoupment and set off rights will not limit the other remedies available to such Party under this Agreement.

10.3 Interest on Late Payments. Any amounts not paid when due under this Agreement will bear interest at the Contract Interest Rate from the date due until paid.

10.4 Disputed Amounts. If either Party, in good faith, disputes any amount due under an invoice provided under this Agreement, such Party must notify the other Party of the specific basis for the dispute and, if the invoice shows an amount due, must pay that portion of the invoice that is undisputed on or before the due date. Any such notice of dispute must be provided within two (2) years of the date of the invoice in which the error first occurred. If any amount disputed by such Party is determined to be due to the other Party, or if the Parties resolve the payment dispute, the amount due must be paid within five (5) Business Days after such determination or resolution, along with interest at the Contract Interest Rate from the date due until the date paid.

10.5 Audit Rights. Each Party, through its authorized representatives, has the right, at its expense upon reasonable notice and during normal business hours, to examine and copy the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made under this Agreement or to verify the other Party's performance of its obligations under this Agreement. Upon request, each Party must provide to the other Party statements evidencing the quantities of Net Output delivered at the Point of Delivery. If any statement is found to be inaccurate, a corrected statement will be issued and, subject to Section 10.4, any amount due from one Party to the

(continued)

other Party as a result of the corrected statement will be promptly paid including the payment of interest at the Contract Interest Rate from the date of the overpayment or underpayment to the date of receipt of the reconciling payment.

SECTION 11
DEFAULTS AND REMEDIES

11.1 Defaults. An event of default ("Event of Default") shall occur with respect to a Party (the "Defaulting Party") upon the occurrence of each of the following events and the expiration of any applicable cure period provided for below:

11.1.1 Defaults by Either Party.

(a) A Party fails to make a payment when due under this Agreement if the failure (i) is not subject to a good faith dispute of the amount due under Section 10.4, and (ii) is not cured within thirty (30) days after the non-defaulting Party gives the Defaulting Party a notice of the default.

(b) The Defaulting Party: (i) makes a general assignment for the benefit of its creditors; (ii) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within thirty (30) days after such filing; (iii) becomes insolvent; or (iv) is unable to pay its debts when due.

(c) The Defaulting Party breaches one of its representations or warranties or fails to perform any material obligation in this Agreement for which an exclusive remedy is not provided and which is not otherwise an Event of Default under this Agreement and such breach or failure is not cured within thirty (30) days after the non-defaulting Party gives the Defaulting Party notice of such breach; provided, however, that if such breach is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within ninety (90) days, then the Defaulting Party will have an additional reasonable period of time to cure the breach, not to exceed ninety (90) days following the date of such notice of breach, provided that the Defaulting Party provides to the other Party a remediation plan within fifteen (15) days following the date of such notice of breach and the Defaulting Party promptly commences and diligently pursues the remediation plan within thirty (30) days following the date of the notice of non-performance.

11.1.2 Defaults by Seller.

(a) Seller fails to post, increase, or maintain the Project Development Security or Default Security as required under this Agreement and such failure is not cured within thirty (30) days after Seller's receipt of written notice from Utility.

(b) Seller fails to cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date and one or more of the following events occur: (i) Seller fails to deliver a draft Schedule Recovery Plan by the Scheduled Commercial Operation Date, as provided in Section 2.4(a); (ii) Seller fails to diligently and continuously finalize and implement its Schedule Recovery Plan and such failure, in either case, is not cured within thirty (30) days from

(continued)

the date of Seller's receipt of notice of such failure from Utility; (iii) Seller fails to achieve Commercial Operation by the Cure Period Deadline.[25]

(c) Seller sells Output or Capacity Rights from the Facility to a party other than Utility in breach of Section 4.3, if Seller does not permanently cease such sale and compensate Utility for the damages arising from the breach within thirty (30) days after Utility gives Seller a notice of default.

(d) Utility receives notice of foreclosure of the Facility or any part thereof by a Lender, mechanic or materialman, or any other holder, of an unpaid lien or other charge or encumbrance, if the same has not been stayed, paid, or bonded around within thirty (30) days of the date on which Utility provides notice to Seller that Utility has received a notice of foreclosure. An assignment in lieu of foreclosure as permitted pursuant to Section 20 of this Agreement and occurring prior to the date that is thirty (30) days after the date on which Utility provides notice to Seller that Utility has received a notice of foreclosure shall cure an Event of Default pursuant to this Section 11.1.2(d).

(e) After the Commercial Operation Date, Seller fails to maintain any Required Facility Documents, Permits or leases/land grants necessary to own or operate the Facility and is not able to obtain the necessary Required Facility Documents or Permits within thirty (30) days after the loss of the applicable Required Facility Documents, Permits or leases/land grants; provided, however, that if such breach is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within ninety (90) days, then Seller will have an additional reasonable period of time to cure the breach, not to exceed ninety (90) days following the date of such notice of breach, provided that Seller provides Utility with a remediation plan within fifteen (15) days following the date of such notice of breach and Seller promptly commences and diligently pursues the remediation plan within thirty (30) days following the date of the notice of non-performance.

(f) Seller's Abandonment of construction or operation of the Facility, such Abandonment continues and no draft Schedule Recovery Plan is implemented within thirty (30) days after Seller's receipt of written notice from Utility or, in the event a Schedule Recovery Plan is implemented, Seller fails to diligently and continuously implement said Schedule Recovery Plan and such failure is not cured within thirty (30) days from the date of Seller's receipt of notice of such failure from Utility.

(g) Seller fails to satisfy the requirements of the Performance Guarantee for the number of consecutive Contract Years specified in Exhibit F.

---

[25] **Note to Form** – This provision to be replaced for PPAs with operational QFs with the following language: "Seller fails to achieve Initial Delivery on or before the Scheduled Initial Delivery Date and such failure is not cured within thirty (30) days after Utility gives Seller notice of such failure; provided, however, that if such failure is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within ninety (90) days, then Seller will have an additional reasonable period of time to cure the breach, not to exceed ninety (90) days following the date of such notice from Utility; provided that Seller provides to Utility a remediation plan within fifteen (15) days following the date of Utility's notice and Seller promptly commences and diligently pursues the remediation plan within thirty (30) days following the date of Utility's notice of non-performance."

(continued)

(h) Seller fails to satisfy the requirement to maintain QF status under Section 7.1, and such failure is not cured within thirty (30) days from the date of Seller's receipt of notice of such failure from Utility.

(i) With respect to an Off-System QF, a Seller Event of Default occurs under Exhibit L with respect to Seller's obligation to reserve Firm Delivery for the term of the Agreement.

11.1.3 Utility Failure to Purchase.¶ Utility fails to receive or purchase all or part of the Net Output required to be purchased under this Agreement and such failure is not excused under this Agreement, including without limitation the provisions of Section 4.5 or Seller's failure to perform, and such failure is not cured within thirty (30) days from the date of Utility's receipt of notice of such failure from Seller.

11.2 Remedies for Events of Default.

11.2.1 Remedy for Seller's Failure to Deliver. ¶ Upon the occurrence and during the continuation of an Event of Default of Seller under Section 11.1.2(c), Seller must pay Utility within thirty (30) days after receipt of invoice, an amount equal to the sum of (a) Utility's Cost to Cover multiplied by the Net Output delivered to a party other than Utility, (b) additional transmission charges, if any, reasonably incurred by Utility in moving replacement energy to the Point of Delivery or if not there, to such points in Utility's control area as determined by Utility, (c) any additional cost or expense incurred as a result of Seller's default, as determined by Utility in a commercially reasonable manner, and (d) to the extent Seller is required to convey Environmental Attributes to Utility under this Agreement associated with the Net Output delivered to a party other than Utility, any additional costs Utility reasonably incurs to acquire replacement Environmental Attributes. The invoice for such amount must include a written statement explaining in reasonable detail the calculation of such amount.

11.2.2 Remedy for Utility's Failure to Purchase. ¶ Upon the occurrence and during the continuation of an Event of Default of Utility under Section 11.1.3, Utility must pay Seller, on the earlier of the date payment would otherwise be due in respect of the month in which the failure occurred or within thirty (30) days after receipt of invoice, an amount equal to Seller's Cost to Cover multiplied by the amount of Net Output not purchased. The invoice for such amount must include a written statement explaining in reasonable detail the calculation of such amount.

11.2.3 Remedy for Seller's Failure to Provide Capacity Rights, Ancillary Services and Environmental Attributes. ¶ Seller is liable for Utility's actual damages in the event Seller fails to sell or deliver all or any portion of the Capacity Rights, Ancillary Services and, if applicable, Environmental Attributes to Utility.

11.2.4 Remedy for Seller's Failure to Satisfy Performance Guarantee. ¶ Upon the occurrence and during the continuation of an Event of Default of Seller under Section 11.1.2(g), Seller must pay Utility an amount in damages equal to the sum as calculated pursuant to Exhibit F and in a manner as prescribed by Exhibit F.

11.2.5 Remedies Generally. ¶ Except in circumstances in which a remedy provided for in this Agreement is described as a Party's sole or exclusive remedy, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law, equity or this Agreement. Further, in the case of a default by Seller, Utility may offset its damages against any payment due Seller. The rights contemplated by this Section 11 are cumulative such that the exercise of one or more rights does not constitute a waiver of any other rights.

(continued)

11.3 Termination and Remedies. From and during the continuance of an Event of Default, the non-defaulting Party may terminate this Agreement by notice to the other Party designating the date of termination and delivered to the defaulting Party no less than thirty (30) days before such termination date. The notice required under this Section 11.3 may be provided in the notice of default (and does not have to be a separate notice) before the applicable cure period(s) have lapsed and an Event of Default has occurred provided that the non-defaulting Party complies with the terms of this Section 11.3 and that the stated termination date is no earlier than the first (1st) day following expiration of the fifteen (15) day period or the first (1st) day following the expiration of the applicable cure period(s), whichever occurs last ("Earliest Termination Date"). Where Seller is the non-defaulting Party, Seller must provide copies of such termination notice to the notice addresses of the then-current President and General Counsel of Utility by registered overnight delivery service or by certified or registered mail, return receipt requested. A termination notice must state prominently in type font no smaller than 14-point capital letters that "THIS IS A TERMINATION NOTICE UNDER A PPA. YOU MUST CURE A DEFAULT, OR THE PPA WILL BE TERMINATED," must state any amount alleged to be owed, and must include wiring instructions for payment. Notwithstanding any other provision of this Agreement to the contrary, the non-defaulting Party will not have any right to terminate this Agreement if the default that gave rise to the termination right is cured by the Earliest Termination Date.

In the event of a termination of this Agreement:

(a) Each Party must pay to the other all amounts due the other under this Agreement for all periods prior to termination, subject to offset by the non-defaulting Party against damages incurred by such Party.

(b) The amounts due under this Section 11.3 must be paid within thirty (30) days after the billing date for such charges and will bear interest at the Contract Interest Rate from the date of termination until the date paid. The foregoing does not extend the due date of, or provide an interest holiday for, any payments otherwise due under this Agreement.

(c) Without limiting the generality of the foregoing, the provisions of Sections 1, 4.1, 4.4, 4.6, 4.7, 5.4, 5.5, 5.6, 6.2.3, 6.3 6.12.3, 6.12.4, 6.12.4, 6.12.9, 6.13, 10.2, 10.3, 10.4, 10.5, 11.3, 11.4, 11.5, 11.6, 11.7, 11.8, 12, 13, 15, 16, 17, 18, 19, 20, 21, 22, 23 and 24 survive the termination of this Agreement.

11.4 Termination of Duty to Buy. If this Agreement is terminated because of an Event of Default by Seller, and Seller wishes to again sell Net Output to Utility following such termination, Utility in its sole discretion may require that Seller do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the last day of the Term of this Agreement had it not been earlier terminated. In such case, Utility may require Seller to post Default Security even if it meets the Credit Requirements. Seller agrees that it will not take any action or permit any action to occur the result of which avoids or seeks to avoid the restrictions in this Section 11.4, e.g., through use or establishment of a special purpose entity or other Affiliate.

11.5 Termination Damages. If this Agreement is terminated by Utility as a result of an Event of Default by Seller, termination damages owed by Seller to Utility will be the positive difference, if any, between (a) Utility's estimated costs to secure replacement power and Environmental Attributes, if applicable, for a period of twenty-four (24) months following the date of termination, including any associated transmission necessary to deliver such replacement power; and (b) the Contract Price for such twenty-four- (24) month period ("Termination Damages"). Utility must calculate the Termination Damages on a monthly basis in a

(continued)

commercially reasonable manner and will be deemed to have done so if it calculates such damages for each day of the twenty-four- (24) month period by multiplying (a) the forecasted Net Output for such day as provided in the 12x24 forecast provided by Seller under Section 6.7, or if such forecast is not available, the Expected Monthly Net Output for the applicable month, expressed in MWhs per month, divided by the number of days of the applicable month, by (b) the Utility's Cost to Cover for such day. To the extent Utility reasonably incurs additional costs to purchase replacement power, including, for example, transmission charges to deliver replacement energy to the Point of Delivery, and, to the extent Seller is required to convey Environmental Attributes to Utility under this Agreement during any portion of the twenty-four- (24) month period, and Utility reasonably incurs additional costs to acquire replacement Environmental Attributes, such sums, in each case as applicable, shall be added to the Termination Damages. Utility will provide to Seller a written statement explaining in reasonable detail the calculation of Termination Damages.

Notwithstanding the foregoing, Termination Damages for the twenty-four- (24) month term may not exceed the aggregate amount Utility would have incurred to purchase Seller's Net Output and Environmental Attributes had the Agreement not been terminated. Termination Damages are due by Seller within thirty (30) days after receipt of the written statement of Termination Damages from Utility. Each Party agrees and acknowledges that the damages that Utility would incur due to Seller's Event of Default would be difficult or impossible to predict with certainty, it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Termination Damages as agreed to in this Section 11.5 are a fair and reasonable calculation of such damages.

11.6 Duty/Right to Mitigate. Each Party agrees that it has a duty to mitigate damages and will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of its obligations under this Agreement to the extent mitigation is relevant to the calculation of damages. In furtherance of the immediately preceding sentence, (a) with respect to Seller and to the extent permitted by Requirements of Law and the Generation Interconnection Agreement, Seller must use commercially reasonable efforts to maximize the price received by Seller from third parties for Net Output and Environmental Attributes not purchased and accepted by Utility. The duty to mitigate described in this subsection shall not impact or affect the method of determining liquidated damages, including termination damages under Section 11.5 and Delay Damages under Section 2.4.

11.7 Security. If this Agreement is terminated because of an Event of Default by Seller, then Utility may, in addition to pursuing any and all other remedies available at law or in equity (except where otherwise limited herein), proceed against any Security held by Utility in whatever form to reduce the amounts that Seller owes Utility arising from such Event of Default.

11.8 Cumulative Remedies. Except in circumstances in which a remedy provided for in this Agreement is described as a sole or exclusive remedy, the rights and remedies provided to the Parties in this Agreement are cumulative and not exclusive of any rights or remedies of the Parties, and the exercise of one or more rights or remedies does not constitute a waiver of any other rights or remedies.

SECTION 12
INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. ¶ To the extent permitted by Requirements of Law and subject to Section

(continued)

12.1.5, Seller shall indemnify, defend and hold harmless Utility and its Affiliates and each of its and their respective directors, officers, employees, agents, and representatives (collectively, the "Utility Indemnitees") from and against any and all losses, fines, penalties, claims, demands, damages, liabilities, actions or suits of any nature whatsoever (including legal costs and attorneys' fees, both at trial and on appeal, whether or not suit is brought) (collectively, "Liabilities") resulting from, arising out of, or in any way connected with, the breach, performance or non-performance by Seller of its obligations or covenants under this Agreement, or relating to the Facility or the Premises, for or on account of injury, bodily or otherwise, to, or death of, or damage to, or destruction or economic loss of property of, any third party Person, except to the extent such Liabilities are caused by the negligence or willful misconduct of any Utility Indemnitee. Seller is solely responsible for and will indemnify, defend and hold harmless the Utility Indemnitees from and against any and all Liabilities resulting from, arising out of, or in any way connected with the breach by Seller of the Generation Interconnection Agreement.

12.1.2 Indemnity by Utility. ¶ To the extent permitted by Requirements of Law and subject to Section 12.1.5, Utility shall indemnify, defend and hold harmless Seller and its Affiliates and each of its and their respective directors, officers, employees, agents, and representatives (collectively, the "Seller Indemnitees") from and against any and all Liabilities resulting from, arising out of, or in any way connected with, the breach, performance or non-performance by Utility of its obligations or covenants under this Agreement for or on account of injury, bodily or otherwise, to, or death of, or damage to, or destruction or economic loss of property of, any third party Person, except to the extent such Liabilities are caused by the negligence or willful misconduct of any Seller Indemnitee.

12.1.3 Additional Cross Indemnity. ¶ Without limiting Section 12.1.1 and Section 12.1.2,

(a) Seller shall indemnify, defend and hold harmless the Utility Indemnitees from and against all Liabilities resulting from, arising out of, or in any way connected with: (i) the Net Output prior to its delivery by Seller at the Point of Delivery; (ii) any action by any Governmental Authority due to noncompliance by Seller with any Requirements of Law or the provisions of this Agreement; (iii) Utility being deemed by an RTO to be operationally or financially responsible for Seller's performance under the Generation Interconnection Agreement due to Seller's lack of standing as a "scheduling coordinator" or other RTO-recognized designation, qualification, or otherwise; and (iv) Seller's failure to comply with applicable dispatch instructions; except in each case to the extent such Liabilities are caused by the gross negligence, willful misconduct or a breach of this Agreement by any Utility Indemnitee; and

(b) Utility shall indemnify, defend and hold harmless the Seller Indemnitees from and against all Liabilities resulting from, arising out of, or in any way connected with: (i) the Net Output at and after its delivery to Utility at the Point of Delivery in accordance with this Agreement; and (ii) any action by any Governmental Authority due to noncompliance by Utility with any Requirements of Law or the provisions of this Agreement, except in each case to the extent such Liabilities are caused by the gross negligence, willful misconduct, or a breach of this Agreement by any Seller Indemnitees.

12.1.4 Indemnification Procedures. ¶ Any indemnified party seeking indemnification under this Agreement for any Liabilities shall give the Indemnifying Party notice of such Liabilities promptly but in any event on or before thirty (30) days after the Indemnified Party's actual knowledge of the claim or action giving rise to the Liabilities. Such notice shall describe the Liability in reasonable detail and shall indicate the amount (estimated if necessary) of the Liability that has been, or may be sustained by, the Indemnified Party. To the extent that the indemnifying party will have been actually and materially

(continued)

prejudiced as a result of the failure to provide such notice within such thirty (30) day period, the indemnified party shall bear all responsibility for any additional costs or expenses incurred by the indemnifying party as a result of such failure to provide timely notice. The indemnifying party shall assume the defense of the claim or action giving rise to the Liabilities with counsel designated by the indemnifying party; provided, however, that if the defendants in any such action include both the indemnified party and the indemnifying party and the indemnified party reasonably concludes that there may be legal defenses available to it that are different from or additional to, or inconsistent with, those available to the indemnifying party, the indemnified party shall have the right to select and be represented by separate counsel, at the expense of the indemnifying party. Notwithstanding anything to the contrary contained herein, an indemnified party shall in all cases be entitled to control its own defense, at the expense of the indemnifying party, in any claim or action if it: (a) may result in injunctions or other equitable remedies with respect to the indemnified party; (b) may result in material liabilities which may not be fully indemnified hereunder; or (c) may have a material and adverse effect on the indemnified party (including a material and adverse effect on the tax liabilities, earnings, ongoing business relationships or regulation of the indemnified party) even if the indemnifying party pays all indemnification amounts in full. If the indemnifying party fails to assume the defense of a claim or action, the indemnification of which is required under this Agreement, the indemnified party may, at the expense of the indemnifying party, contest, settle, or pay such claim; provided, however, that settlement or full payment of any such claim or action may be made only with the indemnifying party's consent, which consent will not be unreasonably withheld, conditioned or delayed, or, absent such consent, written opinion of the indemnified party's counsel that such claim is meritorious or warrants settlement.

12.1.5 No Dedication. ¶ Nothing in this Agreement will be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party. No undertaking by one Party to the other under any provision of this Agreement will constitute the dedication of Utility's facilities or any portion thereof to Seller or to the public, nor affect the status of Utility as an independent public utility corporation or Seller as an independent individual or entity.

12.1.6 Consequential Damages. ¶ **EXCEPT AS PROVIDED IN SECTION 12.1.1, SECTION 12.1.2 AND SECTION 12.1.3, NEITHER PARTY WILL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE. THE PARTIES AGREE THAT ANY LIQUIDATED DAMAGES, INCLUDING DELAY DAMAGES, TERMINATION DAMAGES AND PERFORMANCE GUARANTEE DAMAGES, UTILITY'S COST TO COVER DAMAGES AND SELLER'S COST TO COVER DAMAGES, OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT DO NOT REPRESENT SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES AS CONTEMPLATED IN THIS PARAGRAPH.**

12.2 Survival. The provisions of this Section 12 shall survive the termination or expiration of this Agreement.

SECTION 13
INSURANCE

Without limiting any Liabilities or any other obligations of Seller, unless the Facility has a Nameplate Capacity Rating of less than or equal to 200 kW, Seller must secure and continuously carry the insurance coverage specified on Exhibit H commencing with the start of construction activities at the Premises and continuing thereafter during the Term or such longer period as is specified in Exhibit H.

(continued)

SECTION 14
FORCE MAJEURE

14.1 Definition of Force Majeure. "Force Majeure" or an "event of Force Majeure" means an event or circumstance that prevents a Party (the "Affected Party") from performing, in whole or in part, an obligation under this Agreement and that: (a) is not reasonably anticipated by the Affected Party as of the Execution Date; (b) is not within the reasonable control of the Affected Party or its Affiliates; (c) is not the result of the negligence or fault or the failure to act by the Affected Party or its Affiliates; and (d) could not be overcome or its effects mitigated by the use of due diligence by the Affected Party or its Affiliates. Force Majeure includes the following types of events and circumstances (but only to the extent that such events or circumstances satisfy the requirements in the preceding sentence): tornado, hurricane, tsunami, flood, earthquake and other acts of God; fire; explosion; invasion, acts of terrorism, war (declared or undeclared) or other armed conflict; riot, revolution, insurrection or similar civil disturbance; global pandemic (except as excluded below); sabotage; strikes, walkouts, lock-outs, work stoppages, or other labor disputes; and action or restraint by Governmental Authority (except as excluded below); provided that the Affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such action or restraint. Notwithstanding the foregoing, none of the following shall constitute Force Majeure: (i) Seller's ability to sell, or Utility's ability to purchase, energy, Capacity, Ancillary Services or Environmental Attributes at a more advantageous price than is provided under this Agreement; (ii) inability to obtain any supply of goods or services, unless due to an independent event of Force Majeure; (iii) economic hardship, including lack of money or the increased cost of electricity, steel, labor, or transportation; (iv) any breakdown or malfunction of the Facility's equipment (including any serial equipment defect) that is not caused by an independent event of Force Majeure; (v) the imposition upon a Party of costs or taxes; (vi) delay or failure of Seller to obtain or perform any Required Facility Document unless due to an independent event of Force Majeure; (vii) any delay, alleged breach of contract, or failure by Transmission Provider or Interconnection Provider unless due to an independent event of Force Majeure; (viii) maintenance upgrade or repair of any facilities or right of way corridors constituting part of or involving the Interconnection Facilities, whether performed by or for Seller, or other third parties (except for repairs made necessary as a result of an independent event of Force Majeure); (ix) Seller's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to Transmission Provider or Interconnection Provider, unless due to an independent event of Force Majeure; (x) any event attributable to the use of Interconnection Facilities for deliveries of Net Output to any party other than Utility; (xi) any delays or other problems associated with the issuance, suspension, renewal, administration or withdrawal of, or any other problem directly or indirectly relating to, any Permit or the applications therefor where such delays or problems are within the Affected Party's reasonable control; (xii) delays in customs clearance, unless due to an independent event of Force Majeure; (xiii) the imposition of tariffs, anti-dumping or countervailing duties that may apply to any products or equipment or any other fines, penalties or other actions as a result of violation of Requirements of Law regarding unfair trade practices; and (xiv) the occurrence after the Execution Date, of an enactment, promulgation, modification or repeal of one or more Requirements of Law, including regulations or national defense requirements that affects the cost or ability of either Party to perform under this Agreement.

14.2 Suspension of Performance. Neither Party will be liable for any delay in or failure to perform its obligations under this Agreement nor will any such delay or failure become an Event of Default, to the extent such delay or failure is substantially caused by Force Majeure, provided that the Affected Party: (a) provides prompt (and, in any event, not more than five (5) days' notice of such event of Force Majeure to the other Party, describing the particulars of the event of Force Majeure and giving an estimate of its expected duration and the probable impact on the performance of its obligations under this Agreement;

(continued)

(b) exercises all reasonable efforts to continue to perform its obligations under this Agreement; (c) expeditiously takes action to correct or cure the event of Force Majeure so that the suspension of performance is no greater in scope and no longer in duration than is dictated by the event of Force Majeure; (d) exercises all reasonable efforts to mitigate or limit damages to the other Party resulting from the event of Force Majeure; and (e) provides prompt notice to the other Party of the cessation of the event of Force Majeure.

14.3 Force Majeure Does Not Affect Other Obligations. No obligations of either Party that arose before the event of Force Majeure causing the suspension of performance or that arise after the cessation of such event of Force Majeure is excused by such event of Force Majeure.

14.4 Strikes. Notwithstanding any other provision of this Agreement, neither Party will be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.5 Right to Terminate. If a Force Majeure event prevents a Party from substantially performing its obligations under this Agreement for a period exceeding 180 consecutive days, then the Party not affected by the Force Majeure event may terminate this Agreement by giving ten (10) days prior notice to the other Party. Upon such termination, neither Party will have any liability to the other with respect to the period following the effective date of such termination; provided, however, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising under this Agreement before the effective date of such termination.

SECTION 15
SEVERAL OBLIGATIONS

Nothing in this Agreement will be construed to create an association, trust, partnership or joint venture or to impose a trust, partnership or fiduciary duty, obligation or Liability on or between the Parties.

SECTION 16
CHOICE OF LAW

This Agreement will be interpreted and enforced in accordance with the laws of the State of Oregon, applying any choice of law rules that may direct the application of the laws of another jurisdiction.

SECTION 17
PARTIAL INVALIDITY

If any term, provision or condition of this Agreement is held to be invalid, void or unenforceable by a Governmental Authority and such holding is subject to no further appeal or judicial review, then such invalid, void, or unenforceable term, provision or condition shall be deemed severed from this Agreement and all remaining terms, provisions and conditions of this Agreement shall continue in full force and effect. The Parties shall endeavor in good faith to replace such invalid, void or unenforceable terms, provisions or conditions with valid and enforceable terms, provisions or conditions which achieve the purpose intended by the Parties to the greatest extent permitted by law and preserve the balance of the economics and equities contemplated by this Agreement in all material respects.

(continued)

SECTION 18
NON-WAIVER

No waiver of any provision of this Agreement will be effective unless the waiver is provided in writing that (a) expressly identifies the provision being waived, and (b) is executed by the Party waiving the provision. A Party's waiver of one or more failures by the other Party in the performance of any of the provisions of this Agreement will not be construed as a waiver of any other failure or failures, whether of a like kind or different nature.

SECTION 19
GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those Governmental Authorities having jurisdiction over either Party or this Agreement.

SECTION 20
SUCCESSORS AND ASSIGNS

20.1 Restriction on Assignments. Except as provided in this Section 20, neither Party may transfer, sell, pledge, encumber or assign (collectively, "Assign") this Agreement nor any of its rights or obligations under this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld, conditioned or delayed.

20.2 Permitted Assignments.

20.2.1 Assignments to Affiliates. Notwithstanding Section 20.1, either Party may, without the need for consent from the other Party (but with prior notice to the other Party, including the name of the Affiliate), Assign this Agreement to an Affiliate; provided, however, that it shall be a condition precedent to such Assignment that such Affiliate enters into an assignment and assumption agreement pursuant to which such Affiliate assumes all of the assigning Party's obligations under this Agreement and otherwise agrees to be bound by the terms of this Agreement; provided, further that: (a) in the case of Assignment by Utility, such Affiliate must have the same or better credit rating from S&P and Moody's as Utility as of the effective date of such assignment (or if such Affiliate is not rated by S&P and Moody's, the same or better creditworthiness as Utility, as reasonably determined by Seller and (b) in the case of Assignment by Seller: (i) such Affiliate must (A) possess the same or similar experience as Seller (as reasonably determined by Utility) or have engaged the services of a Qualified Operator and (B) possess the same or better credit rating from S&P and Moody's as Seller as of the Execution Date (or if Seller or such Affiliate is not rated by S&P and Moody's, the same or better creditworthiness as Seller, as reasonably determined by Utility); and (ii) any Security required pursuant to Section 8 must be provided, replaced or remain in full force and effect.

20.2.2 Assignments to Other Persons. In addition, Utility may without the need for consent from Seller (but with prior notice to Seller, including the name of the assignee) Assign this Agreement in whole or in part to any Person; provided, however, that it shall be a condition precedent to such Assignment that such assignee: (a) enters into an assignment and assumption agreement pursuant to which such assignee assumes all of Utility's obligations under this Agreement and otherwise agrees to be bound by the terms of this Agreement; (b) has the same or better credit rating from S&P and Moody's as Utility as of the Execution Date (or if such assignee is not rated by S&P and Moody's, the same or better

(continued)

creditworthiness as Utility, as reasonably determined by Seller); (c) if required by applicable Requirements of Law, has received approval from any applicable public utility commission or equivalent or any other applicable Governmental Authority.

20.2.3 Release from Liability. If the foregoing requirements for Assignment in this Section 20.2 have been satisfied, then effective as of the date of such Assignment Utility and Seller, as applicable, will be released from all liability under this Agreement. Any Party seeking to Assign this Agreement shall be solely responsible for paying all costs and expenses of Assignment, including any costs and expenses incurred by the other Party in connection with the review and/or execution and delivery of the assignment and assumption agreement and any other documents required in connection with the Assignment.

SECTION 21
ENTIRE AGREEMENT

This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding the subject matter of this Agreement. No modification of this Agreement is effective unless it is in writing and executed by both Parties.

SECTION 22
NOTICES

All notices, requests, demands, submittals, waivers and other communications required or permitted to be given under this Agreement (each, a "Notice") shall, unless expressly specified otherwise, be in writing and shall be addressed, except as otherwise stated herein, to the addressees and addresses set out in Exhibit K, as the same may be modified from time to time by Notice from the respective Party to the other Party. All Notices required by this Agreement shall be sent by regular first-class U.S. mail, registered or certified U.S. mail (postage paid return receipt requested), overnight courier delivery, or electronic mail. Such Notices will be deemed effective and given upon receipt by the addressee, except that Notices transmitted by electronic mail shall be deemed effective and given on the day (if a Business Day and, if not, on the next following Business Day) on which it is transmitted if transmitted before 16:00 [PPT/MPT], and if transmitted after that time, on the following Business Day, provided that Notices transmitted by electronic mail must be followed up by Notice by other means as provided for in this Section to be effective. If any Notice sent by regular first class U.S. mail, registered or certified U.S. mail postage paid return receipt requested, or overnight courier delivery is tendered to an addressee set out in Exhibit K, as the same may be modified from time to time by Notice from the respective Party to the other Party, and the delivery thereof is refused by such addressee, then such Notice shall be deemed given and effective upon such tender. In addition, Notice of termination of this Agreement under Section 11.3 must contain the information required by Section 11.3 and, where Utility is the Defaulting Party, must be sent to the attention of the then-current President and General Counsel of Utility as required by (and subject to the terms of) Section 11.3, and where Seller is the Defaulting Party, must be sent to the attention of the then-current President and General Counsel of Seller subject to the terms of Section 11.3.

(continued)

SECTION 23
PUBLICITY

Before Seller issues any news release or publicly distributed promotional material regarding this Agreement, Seller must first provide a copy thereof to Utility for its review and approval. Any use of any tradename of Utility or any of its affiliates requires Utility's prior written consent.

SECTION 24
DISAGREEMENTS

24.1 Negotiations. Prior to proceeding with formal dispute resolution, the Parties must first attempt in good faith to resolve informally all disputes arising out of, related to, or in connection with this Agreement. Any Party may give the other Party notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels one level above those employees who have previously been involved in the dispute must meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days after the referral of the dispute to such executives, or if no meeting of such executives has taken place within fifteen (15) days after such referral, then, subject to Section 24.2, either Party may initiate any legal remedies available to the Party. No statements of position or offers of settlement made in the course of the dispute process described in this Section 24.1 will: (a) be offered into evidence for any purpose in any litigation between the Parties; (b) be used in any manner against either Party in any such litigation; or (c) constitute an admission or waiver of rights by either Party in connection with any such litigation. At the request of either Party, any such statements and offers of settlement, and all copies thereof, will be promptly returned to the Party providing the same.

24.2 Alternative Dispute Resolution. If the dispute is not resolved under the procedures provided in Section 24.1, then either Party may initiate an alternative dispute resolution process under Oregon Administrative Rules Chapter 860, Division 2. The costs of any alternative dispute resolution process, including fees and expenses, will be borne equally by the Parties.

24.3 Choice of Forum. To the extent the dispute is not resolved under the procedures provided in Section 24.1 or 24.2, any complaint, claim or action to resolve such dispute shall be brought exclusively in a court in the state of Oregon or governmental agency with jurisdiction over the dispute, including but not limited to any governmental agency having control over either party or this Agreement. By execution and delivery of this Agreement, each Party: (a) accepts the exclusive jurisdiction of such courts or governmental agencies and waives any objection that it may now or hereafter have to the exercise of personal jurisdiction by such courts or governmental agencies over each Party for the purpose of the Proceedings; (b) irrevocably agrees to be bound by any final judgment (after any and all appeals) of any such courts or governmental agencies arising out of the Proceedings; (c) irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of venue of any of the Proceedings brought in such courts or governmental agencies (including any claim that any such Proceeding has been brought in an inconvenient forum) in connection herewith; (d) agrees that service of process in any such Proceeding may be effected by mailing a copy thereof by registered or certified mail, postage prepaid, to such Party at its address stated in this Agreement; and (e) agrees that nothing in this Agreement affects the right to effect service of process in any other manner permitted by law.

24.4 WAIVER OF JURY TRIAL. EACH PARTY KNOWINGLY, VOLUNTARILY, INTENTIONALLY AND IRREVOCABLY WAIVES THE RIGHT TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION

(continued)

BASED ON, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT AND ANY AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER VERBAL OR WRITTEN) OR ACTIONS OF ANY PARTY HERETO. THIS PROVISION IS A MATERIAL INDUCEMENT TO EACH OF THE PARTIES TO ENTER INTO THIS AGREEMENT. EACH PARTY HEREBY WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION, PROCEEDING OR COUNTERCLAIM BASED ON, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT OR ANY OTHER AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY MATTER ARISING HEREUNDER OR THEREUNDER, WITH ANY PROCEEDING IN WHICH A JURY TRIAL HAS NOT OR CANNOT BE WAIVED. THIS PARAGRAPH WILL SURVIVE THE EXPIRATION OR TERMINATION OF THIS AGREEMENT.

(continued)

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed in their respective names as of the date last written below.

SELLER:	**UTILITY**:
[____________________]	[____________________]
By: ______________________________	By: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: __________________________	Date: ______________________________

(continued)

EXHIBIT A
EXPECTED MONTHLY NET OUTPUT[26]

Month	On-Peak Net Output (MWh)	Off-Peak Net Output (MWh)	Total Net Output (MWh)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
First Contract Year Total			

[The values above will be reduced [__]% each Contract Year following the Commercial Operation Date] **OR**

[The energy values above will be reduced each Contract Year following the Commercial Operation Date in accordance with the following Expected Annual Degradation Schedule]

MAXIMUM DELIVERY RATE (MWh or kWh)

[____________________]

[26] **Note to Form** – Prior to executing the Agreement, Seller will be required to provide Utility information sufficient to allow Utility to reasonably verify the output estimates stated in Exhibit A.

(continued)

EXHIBIT B

DESCRIPTION OF SELLER'S FACILITY

[Provide a detailed description of the Facility, including the following, as applicable:]

Type (synchronous or inductive):
Facility Nameplate Capacity Rating (as stated in Seller's FERC Form 556):
Number of Generating Units:
Model:
Number of Phases:
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR):
Rated Output (kW):
Rated Output (kVA):
Rated Voltage (line to line):
Rated Current (A): Stator: ____ A; Rotor: ______ A
Maximum kW Output: ____________ kW as measured at the Point of Delivery (Facility)
Maximum kVA Output: ______kVA (Facility)
Minimum kW Output: _________ kW (Facility)
Number of Phases:
Power factor requirements: ____ Leading and Lagging
Rated Power Factor (PF) or reactive load (kVAR):
Controlled Ramp Rate: ____

The following is a layout of the Facility, including site boundaries of the Premises:

Station service requirements, and other loads served by the Facility, if any:

Location of the Facility: *[Please include city and county, and legal description of parcel*]

(continued)

EXHIBIT C

SELLER'S INTERCONNECTION FACILITIES

[Instructions to Seller:
1. Include description of point of metering, and Point of Delivery
2. Provide interconnection single line drawing of Facility including any transmission facilities on Seller's side of the Point of Delivery.]

(continued)

EXHIBIT D
REQUIRED FACILITY DOCUMENTS

1. *QF Certification*

2. *Interconnection Agreement or, if applicable, the following studies and study agreements completed as of the Effective Date:*

   [INSERT DESCRIPTION]

3. *Real property documents listed in Exhibit E to the Agreement with respect to the Premises.*

4. *Licenses, Permits and Authorizations, including:*

   [INSERT DESCRIPTION]

5. *Other Required Facility Documents:*

   [INSERT DESCRIPTION]

[Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be added.]

(continued)

EXHIBIT E

LEASES AND REAL ESTATE DOCUMENTS

(continued)

EXHIBIT F

MECHANICAL AVAILABILITY GUARANTEE – WIND, SOLAR AND HYDRO RESOURCES

1. Availability Guarantee. Seller guarantees that the Facility will achieve an Actual Availability Percentage (as defined below) of at least ninety percent (90%) during each covered Contract Year ("Availability Guarantee"). The Actual Availability Percentage will be calculated annually, commencing with the first (1st) day of the second Contract Year after Initial Delivery Date for existing QFs and with the first (1st) day of the fourth Contract Year after Commercial Operation for new QFs. For example, for an existing QF that achieves an Initial Delivery Date of January 1, 2026, the Actual Availability Percentage will be calculated on January 1, 2027, based on Facility data from the previous Contract Year. For a new QF that achieves Commercial Operation on January 1, 2026, the Actual Availability Percentage will be calculated on January 1, 2029, based on Facility data from the previous Contract Year.

"Actual Availability Percentage" for a particular Contract Year is calculated as follows:

Actual Availability Percentage = 100 x (Operational Hours in the Contract Year) / (Number of Hours in the Contract Year x Number of Generating Units in the Facility)

"Operational Hours" means the total across all of the Facility's Generating Units of (i) the number of hours each of the Generating Units was capable of producing power regardless of actual weather, season and time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Delivery Point; (ii) the number of hours during which each Generating Unit was not available to generate due to a Force Majeure event, a default by Utility under this Agreement, or a default by Utility under the Generation Interconnection Agreement; and (iii) the number of hours during which each Generating Unit was not available to generate due to a Planned Outage, but only to the extent such hours were not already assumed in Seller's calculation of Expected Net Output and do not exceed 200 hours per Generating Unit per Contract Year. However, if any of the events described in items (i) through (iii) occur simultaneously, then the relevant period of time will only be counted once in order to prevent double counting. Operational Hours do not include hours when (i) the Facility or any portion thereof was unavailable solely due to Seller's non-conformance with the Generation Interconnection Agreement or (ii) the Facility or any portion thereof was paused or withdrawn from use by Seller for reasons other than those covered in this definition.

"Generating Unit" means a complete electrical generation system within the Facility that is able to generate and deliver energy to the Point of Interconnection independent of other Generating Units within the Facility. For example, for a solar facility, a Generating Unit is an inverter and the panels associated with such inverter. The number of Generating Unit's for the Facility shall be identified in Exhibit B.

If the Actual Availability Percentage in any Contract Year commencing with the first full Contract Year that is subject to this Availability Guarantee falls below ninety percent (90%), the resulting shortfall will be expressed in MWh as the "On-Peak Availability Shortfall" or the "Off-Peak Availability Shortfall," as applicable, or together, the "Availability Shortfalls." For each Contract Year, the Availability Shortfalls will equal the mathematical difference between the Availability Guarantee and the Availability, multiplied by the Expected Net Output for the applicable Contract Year, expressed in the formula below:

On-Peak Availability Shortfall (MWh) = (90 (%) minus Actual Availability Percentage (%)) multiplied by the total On-Peak Expected Net Output (MWh) as defined in Exhibit A

(continued)

Off-Peak Availability Shortfall (MWh) = (90 (%) minus Actual Availability Percentage (%)) multiplied by the total Off-Peak Expected Net Output (MWh) as defined in Exhibit A

2. Damages Calculation for Availability Shortfall. If an Availability Shortfall occurs in any Contract Year, Seller will compensate Utility damages, if any, for both Energy Shortfall (as defined below) REC Shortfall (as defined below) associated with the Availability Shortfall.

(a) Energy Shortfall. The "Energy Shortfall" is comprised of the following cost components:

i. Replacement Energy Cost. Seller shall pay Utility an amount for such deficiency equal to:
   a. The On-Peak Availability Shortfall for the Contract Year, multiplied by the average On-Peak Utility's Cost to Cover for such Contract Year; plus
   b. The Off-Peak Availability Shortfall for the Contract Year, multiplied by the average Off-Peak Utility's Cost to Cover for such Contract Year.

ii. Potential Transmission Adjustment. In the event the replacement energy procured by Utility as a result of Seller's failure to deliver the Availability Shortfall results in incremental ancillary services and transmission costs, Seller shall pay Utility an amount equal to such costs incurred by Utility, provided however that Utility shall provide commercially reasonable evidence that it incurred such costs as a result of Seller's failure to deliver in accordance with the Availability Guarantee.

(b) REC Shortfall. The "REC Shortfall" is equal to the number of renewable energy certificates ("RECs") Seller would have delivered to Utility had Seller met the Availability Guarantee. In the case of a REC Shortfall, Seller shall owe Utility the Replacement Bundled REC price, identified by Utility, multiplied by the REC Shortfall. Utility shall use commercially reasonable efforts to mitigate the amount owed by Seller under this Section 2. For purposes of this Exhibit F, "Replacement Bundled REC" shall mean a REC bundled and simultaneously delivered with the associated qualifying energy generated by an Oregon Renewable Portfolio Standard eligible renewable energy resource and delivered bundled to Utility. The Replacement Bundled REC price shall be determined by Utility taking the lower of two dealer quotes representing a live offer to sell bundled RECs in a quantity sufficient to cover the REC Shortfall.

Each Party agrees and acknowledges that (i) the damages that Utility would incur due to the Facility's failure to achieve the Availability Guarantee would be difficult or impossible to predict with certainty and (ii) the damages calculation methodology contemplated by this provision are a fair and reasonable calculation of such damages.

3. Invoicing for Availability Shortfall. Following the end of each Contract Year, Utility will deliver to Seller an invoice showing Utility's computation of Availability Shortfall, if any, for the prior Contract Year and any amount due to Utility for damages calculated pursuant to this Exhibit F. In preparing such invoices, Utility will utilize the fault log provided to Utility for the applicable Contract Year under Section 6.12.1, provided that if the fault log for any portion of such Contract Year is then incomplete or otherwise not available, Utility may rely other information as may be available to Utility at the time of invoice preparation. Utility shall have the right to offset any payment due under this Exhibit F in accordance with Section 10.2 of the Agreement. Seller must pay to Utility on or before the twentieth (20th) day following the receipt of such invoice. Any amounts due under this Exhibit F are subject to Section 10.3, and all disputes regarding such invoices are subject to Section 10.4. Objections not made by Seller within the twenty (20)-

(continued)

day period will be deemed waived.

4. Event of Default. The occurrence of an Availability Shortfall for two (2) consecutive Contract Years shall be a Seller Event of Default, and Utility shall be entitled to the rights and remedies set forth in Section 11 of the Agreement.

(continued)

MINIMUM DELIVERY GUARANTEE – GEOTHERMAL, BIOMASS AND OTHER BASELOAD RENEWABLE RESOURCES

1. Output Guarantee. Seller is obligated to deliver a quantity of Net Output during each Contract Year which is equal to the Output Guarantee. Seller's compliance with the Output Guarantee will be calculated annually, commencing with the first (1st) day of the second Contract Year after the Commercial Operation Date or Initial Delivery Date, as applicable, based on Facility data from the previous Contract Year.

"Output Guarantee" for any Contract Year means ninety percent (90%) of the Expected Net Output of the Facility for such Contract Year, which shall be adjusted for Seller Uncontrollable Minutes.

"Seller Uncontrollable Minutes" means, for the Facility in any Contract Year, the total number of minutes during such Contract Year during which the Facility was unable to deliver Net Output to Utility (or during which Utility failed to accept such delivery) due to one or more of the following events, each as recorded by Seller's Supervisory Control and Data Acquisition ("SCADA") System and indicated by Seller's electronic fault log: (a) a Force Majeure event; (b) to the extent not caused by Seller's actions or omissions, a curtailment in accordance with Section 4.5; and (c) a default by Utility under this Agreement; provided, however, that if any of the events described above in items (a) through (c) occur simultaneously, then the relevant period of time will only be counted once in order to prevent double counting. Seller Uncontrollable Minutes do not include minutes when (i) the Facility or any portion thereof was unavailable solely due to Seller's non-conformance with the Generation Interconnection Agreement or (ii) the Facility or any portion thereof was paused or withdrawn from use by Seller for reasons other than those covered in this definition.

"Output Shortfall" for any Contract Year will be the Output Guarantee, less the actual Net Output received at the Point of Delivery (or accepted by Utility) in such Contract Year. The Output Shortfall cannot be less than zero (0).

The Output Shortfall shall not be calculated until the completion of the first Contract Year after Commercial Operation and will be calculated as follows:

On-Peak Output Shortfall (MWh) = Output Guarantee, applied to Expected Net Output for On-Peak Hours, minus total actual On-Peak Net Output delivered to the Point of Delivery

Off-Peak Output Shortfall (MWh) = Output Guarantee, applied to Expected Net Output for Off-Peak Hours, minus total actual Off-Peak Net Output delivered to the Point of Delivery

2. Damages Calculation for Output Shortfall. If the product of the Output Shortfall calculation provided above is a positive number, Seller will compensate Utility damages, if any, for both Energy Shortfall (as defined below) and REC Shortfall (as defined below) associated with the Output Shortfall.

(a) Energy Shortfall. The "Energy Shortfall" is comprised of the following cost components:

i. Replacement Energy Cost. Seller shall pay Utility an amount for such deficiency equal to:
   a. The On-Peak Output Shortfall for the Contract Year, multiplied by the average On-Peak Utility's Cost to Cover for such Contract Year; plus
   b. The Off-Peak Output Shortfall for the Contract Year, multiplied by the average Off-Peak Utility's Cost to Cover for such Contract Year.

(continued)

ii. Potential Transmission Adjustment. In the event the replacement energy procured by Utility as a result of Seller's failure to deliver the Output Shortfall results in incremental ancillary services and transmission costs, Seller shall pay Utility an amount equal to such costs incurred by Utility, provided however that Utility shall provide commercially reasonable evidence that it incurred such costs as a result of Seller's failure to deliver in accordance with the Output Guarantee.

(b) REC Shortfall. The "REC Shortfall" is equal to the number of renewable energy certificates ("RECs") Seller would have delivered to Utility had Seller met the Output Guaranty. Seller shall owe Utility the Replacement Bundled REC price, identified by Utility, multiplied by the REC Shortfall. Utility shall use commercially reasonable efforts to mitigate the amount owed by Seller under this Section 2. For purposes of this Exhibit F, "Replacement Bundled REC" shall mean a REC bundled and simultaneously delivered with the associated qualifying energy generated by an Oregon Renewable Portfolio Standard eligible renewable energy resource and delivered bundled to Utility. The Replacement Bundled REC price shall be determined by Utility taking the lower of two dealer quotes representing a live offer to sell bundled RECs in a quantity sufficient to cover the REC Shortfall.

Each Party agrees and acknowledges that (i) the damages that Utility would incur due to the Facility's failure to achieve the Output Guaranty would be difficult or impossible to predict with certainty and (ii) the damages calculation methodology contemplated by this provision are a fair and reasonable calculation of such damages.

3. Invoicing for Output Shortfall. Following the end of each Contract Year, Utility will deliver to Seller an invoice showing Utility's computation of Output Shortfall, if any, for the prior Contract Year and any amount due to Utility for damages calculated pursuant to this Exhibit F. In preparing such invoices, Utility will utilize the meter data provided to Utility for the applicable Contract Year, provided that if the meter data for any portion of such Contract Year is then incomplete or otherwise not available, Utility may also rely on historical averages and other information as may be available to Utility at the time of invoice preparation. Utility shall have the right to offset any payment due under this Exhibit F in accordance with Section 10.2., Seller must pay to Utility on or before the twentieth (20th) day following the receipt of such invoice. Any amounts due under this Exhibit F are subject to Section 10.3, and all disputes regarding such invoices are subject to Section 10.4. Objections not made by Seller within the twenty (20)-day period will be deemed waived.

4. Event of Default. The occurrence of an Output Shortfall for three (3) consecutive Contract Years shall be a Seller Event of Default, and Utility shall be entitled to the rights and remedies set forth in Section 11 of the Agreement.

(continued)

EXHIBIT G

SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO UTILITY

[DATE]

Director, Transmission Services
Utility
[Utility Address]

RE: Queue Number (if available): ________

To Whom it May Concern:

_______________________ ("Seller") hereby voluntarily authorizes Utility's Transmission business unit to share Seller's interconnection information with marketing function employees of Utility. Seller acknowledges that Utility did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

____

(continued)

EXHIBIT H
REQUIRED INSURANCE

1.1 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller must secure and continuously carry with an insurance company or companies rated not lower than “A-/VII” by the A.M. Best Company the insurance coverage specified below:

1.1.1 Workers’ Compensation to cover claims under applicable State or Federal workers’ compensation laws.

1.1.2 Employers’ Liability with limits not less than $1,000,000 policy limit.

1.1.3 Commercial General Liability with a limit of not less than $1,000,000 each occurrence/ combined single limit.

1.1.4 Business Automobile Liability to cover liability arising out of any auto (including owned, hired, and non-owned autos) used in connection with the Facility with a limit of not less than $1,000,000 combined single limit.

1.1.5 Umbrella/excess Liability with a limit of not less than $5,000.000.

1.1.6 All-risk property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The All-Risk Policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The All-Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

1.2 Additional Provisions or Endorsements.

1.2.1 Except for workers’ compensation, employer’s liability, and property insurance, the policies required must include provisions or endorsements as follows:

(a) naming Utility, parent, divisions, officers, directors and employees as additional insureds;

(b) include provisions that such insurance is primary insurance with respect to the interests of Utility and that any other insurance maintained by Utility is excess and not contributory insurance with the insurance required under this schedule; and

(c) cross liability coverage or severability of interest.

1.2.2 Unless prohibited by applicable law, all required insurance policies must contain provisions that the insurer will have no right of recovery or subrogation against Utility.

1.3 Certificates of Insurance. Seller must provide Utility with certificates of insurance within ten (10) days after the date by which such policies are required to be obtained, in ACORD or similar industry form. The certificates must indicate that the insurer will provide thirty (30) days prior written notice of cancellation. If any coverage is written on a “claims-made” basis, the certification accompanying the policy must conspicuously state that the policy is “claims made.”

1.4 Term of Commercial General Liability Coverage. Commercial general liability coverage must be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

1.5 Periodic Review. Utility may review this schedule of insurance as often as once every two (2)

(continued)

years. Subject to applicable regulations and limitations established by the Commission from time to time, Utility may in its discretion require Seller to make reasonable changes to the policies and coverages described in this Exhibit to the extent reasonably necessary to cause such policies and coverages to conform to the insurance policies and coverages typically obtained or required for power generation facilities comparable to the Facility at the time Utility's review takes place.

(continued)

EXHIBIT I

NERC EVENT TYPES[27]

Event Type	**Description of Outages**
U1	Unplanned (Forced) Outage—Immediate – An outage that requires immediate removal of a unit from service, another outage state or a Reserve Shutdown state. This type of outage results from immediate mechanical/electrical/hydraulic control systems trips and operator-initiated trips in response to unit alarms.
U2	Unplanned (Forced) Outage—Delayed – An outage that does not require immediate removal of a unit from the in-service state but requires removal within six (6) hours. This type of outage can only occur while the unit is in service.
U3	Unplanned (Forced) Outage—Postponed – An outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend. This type of outage can only occur while the unit is in service.
SF	Startup Failure – An outage that results from the inability to synchronize a unit within a specified startup time period following an outage or Reserve Shutdown. A startup period begins with the command to start and ends when the unit is synchronized. An SF begins when the problem preventing the unit from synchronizing occurs. The SF ends when the unit is synchronized or another SF occurs.
MO	Maintenance Outage – An outage that can be deferred beyond the end of the next weekend, but requires that the unit be removed from service before the next planned outage. (Characteristically, a MO can occur any time during the year, has a flexible start date, may or may not have a predetermined duration and is usually much shorter than a PO.)
ME	Maintenance Outage Extension – An extension of a maintenance outage (MO) beyond its estimated completion date. This is typically used where the original scope of work requires more time to complete than originally scheduled. Do not use this where unexpected problems or delays render the unit out of service beyond the estimated end date of the MO.
PO	Planned Outage – An outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks and occurs only once or twice a year.
PE	Planned Outage Extension – An extension of a planned outage (PO) beyond its estimated completion date. This is typically used where the original scope of work requires more time to complete than originally scheduled. Do not use this where unexpected problems or delays render the unit out of service beyond the estimated end date of the PO.

[27] **Note to Form** – This table will be adjusted as necessary to conform with NERC requirements as they exist at the time of PPA execution.

(continued)

EXHIBIT J
SCHEDULE XX AND PRICING SUMMARY TABLE

(continued)

EXHIBIT K
PARTY NOTICE INFORMATION

Notices	Utility	Seller
All Notices:		
All Invoices:		
Scheduling:		
Payments:		
Wire Transfer:		
Credit and Collections:		
Notices of an Event of Default or Potential Event of Default:		

(continued)

EXHIBIT L

OFF-SYSTEM ADDENDUM

WHEREAS, Seller's Facility will not interconnect directly to Utility's System;

WHEREAS, Seller and Utility have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from its Facility to Utility via one (or more) third-party Transmission Providers;

WHEREAS, Utility desires that Seller schedule delivery of Net Output on a firm, hourly basis; and

WHEREAS, Utility does not intend to buy, and Seller does not intend to deliver, more or less than the Net Output of the Facility (except as expressly provided, below);

THEREFORE, Seller and Utility do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

Capitalized terms in this Exhibit L are defined in the Agreement or this Exhibit L:

"Day" means 0:00 hours to 24:00 hours, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Delivery Deficit" means any increment of the Facility's hourly Net Output, expressed in MWh, that is generated in excess of the scheduled hourly energy or capacity delivered to the Point of Delivery during that same hour.

"Firm Delivery" means uninterruptible transmission service (i.e., NERC priority level 7) that is reserved and/or scheduled between the Point of Interconnection and the Point of Delivery pursuant to Seller's Transmission Agreement(s).

"Off-Peak Surplus Delivery" means any positive difference, expressed in MWh, in a given calendar month between the total energy delivered in Off-Peak Hours by the Facility to Utility and the Facility's total Net Output in Off-Peak Hours for the calendar month, i.e., the positive difference between the aggregate Supplemented Delivery for the calendar month and the aggregate Delivery Deficit for the same calendar month, in each case, during Off-Peak Hours.

"On-Peak Surplus Delivery" means any positive difference, expressed in MWh, in a given calendar month between the total energy delivered in On-Peak Hours by the Facility to Utility and the Facility's total Net Output in On-Peak hours for the calendar month, i.e., the positive difference between the aggregate Supplemented Delivery for the calendar month and the aggregate Delivery Deficit for the same calendar month, in each case, during Off-Peak Hours.

(continued)

"Supplemented Delivery" means any increment of scheduled hourly energy or capacity, expressed in MWh, delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"Surplus Delivery" means collectively, Off-Peak Surplus Delivery and On-Peak Surplus Delivery.

SUPPLEMENTAL PROVISIONS

1. Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the third-party Transmission Provider(s) and shall at all times during the term of the Agreement hold rights sufficient to reserve Firm Delivery of Net Output up to the Maximum Delivery Rate to the Point of Delivery for the Term of the Agreement (i.e., such as through rollover rights). In the event Seller breaches the foregoing obligation and fails to cure such breach within thirty (30) days written notice from Utility, a Seller Event of Default shall have occurred. In addition, with respect to any deliveries of Net Output for which Firm Delivery is not secured, Seller will be paid in the manner described in Section 5.1.1. of the Agreement in lieu of the Contract Price.

2. Seller's Responsibility to Schedule Delivery. Seller shall schedule energy with NERC E-tags, pursuant to the most current NERC and WECC scheduling rules and practices, for all deliveries of energy hereunder to the Point of Delivery, by 6:00:00 [PPT/MPT] of the customary WECC pre-scheduling day for each day during the Term when Seller is delivering Net Output. Seller shall schedule the Facility as the identified e-Tag source. Seller may not net or otherwise combine schedules from resources other than the Facility. Seller shall not schedule any energy to be delivered to Utility pursuant to this Agreement using a Dynamic or Pseudo-Tie e-Tag as such terms are defined and used by NERC. Seller and Utility shall maintain records of hourly energy schedules for accounting and operating purposes. The final e-Tag shall be the controlling evidence of the Parties' schedule. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour.

3. Seller's Responsibility to Maintain Interconnection Facilities. Utility shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Interconnection. Utility shall not pay any costs arising from Seller interconnecting its Facility with the Interconnection Provider.

4. Seller's Responsibility to Pay Transmission Costs. Seller shall make all arrangements for, and pay all costs associated with, delivering Net Output to the Point of Delivery, including without limitation costs to schedule energy into Utility's System.

5. Energy Reserve Requirements. Seller is responsible for obtaining all generation reserves as required by the third-party Transmission Provider(s) and WECC and/or as required by any other governing agency or industry standard to deliver the Net Output to the Point of Delivery, at no cost to Utility.

6. Seller's Responsibility to Report Net Output and Supplemented Delivery. On or before the tenth (10th) day following the end of each calendar month, Seller shall send a report containing the information in **Example 1** below from the previous calendar month, in columnar

(continued)

format substantially similar to **Example 1** below. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by Utility. For each day Seller is late delivering the certified report, Utility shall be entitled to postpone its payment deadline in Section 10 of this Agreement by one (1) Business Day. Seller hereby grants Utility the right to audit its certified reports of hourly Net Output and agrees to allow Utility to have access to imbalance information kept by the Transmission Provider(s). In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three (3) years from the date of discovery.

7. Seller's Supplemental Representations, Warranties and Covenants. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller represents, warrants, and covenants with respect to each delivery of energy to the Point of Delivery that:

(a) Seller's Surplus Delivery, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

(b) The third-party Transmission Provider(s) requires Seller to procure energy imbalance ancillary service, as a condition of providing transmission service;

(c) The third-party Transmission Provider(s) requires Seller to schedule deliveries of Net Output in increments of no less than one (1) MW;

(d) Seller is not attempting to sell Utility energy or capacity in excess of the Facility's Net Output; and

(e) The energy imbalance ancillary service is designed to correct a mismatch between energy scheduled by the Seller and the actual real-time production by the Facility.

8. Acceptance of Supplemented Delivery. In reliance upon Seller's warranties in Section 7, above, Utility agrees to accept deliveries of imbalance ancillary service energy from Seller in the form of Supplemented Delivery; provided, however, that Utility is not obligated to pay for Surplus Delivery.

Example 1:

Day	Hour Ending (HE)	Net Output at POI	Maximum Delivery Rate	Net Output in Excess of Maximum Delivery	Scheduled/ Delivered Energy (per e-Tag)	On-Peak Supplemented Delivery/ Delivery Deficit	Off-Peak Supplemented Delivery/ Delivery Deficit
1	1	-	1.50	-	-		-
1	2	(0.01)	1.50	-	-		-
1	3	(0.01)	1.50	-	-		-
1	4	(0.01)	1.50	-	-		-
1	5	(0.01)	1.50	-	-		-
1	6	0.64	1.50	-	1.00		0.36
1	7	0.83	1.50	-	1.00	0.17	
1	8	0.89	1.50	-	1.00	0.11	

(continued)

1	9	0.99	1.50	-	1.00	0.01	
1	10	1.19	1.50	-	1.00	(0.19)	
1	11	1.29	1.50	-	1.00	(0.29)	
1	12	1.34	1.50	-	1.00	(0.34)	
1	13	1.44	1.50	-	1.00	(0.44)	
1	14	1.49	1.50	-	1.00	(0.49)	
1	15	1.48	1.50	-	1.00	(0.48)	
1	16	1.54	1.50	0.04	2.00	0.50	
1	17	1.59	1.50	0.09	2.00	0.50	
1	18	1.59	1.50	0.09	2.00	0.50	
1	19	0.99	1.50	-	1.00	0.01	
1	20	0.75	1.50	-	1.00	0.25	
1	21	0.58	1.50	-	1.00	0.42	
1	22	(0.01)	1.50	-	-	-	
1	23	(0.01)	1.50	-	-		-
1	24	(0.01)	1.50	-	-		-
…	…						
Total		18.55	36.00	0.22	19.00	0.24 (On-Peak Surplus Delivery*)	0.36 (Off-Peak Surplus Delivery*)

On-Peak Scheduled/Delivered Energy (MWhs): 18.00
Off-Peak Scheduled/Delivered Energy (MWhs): 1.00

Total MWhs Utility will pay for:

On-Peak MWhs: 18.00 – 0.24 = 17.76 MWhs
Off-Peak MWhs: 1.00 – 0.36 = 0.64 MWhs

Total MWhs: 18.40 MWhs

*Utility will accept but will not be obligated to pay for Surplus Delivery, per the terms of this Exhibit L and OAR 860-029-0121.

(continued)

PacifiCorp's

Revised Oregon Standard Avoided Cost Rates Schedule

CLEAN

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

- For power purchased from Baseload Renewable Qualifying Facilities and Wind Qualifying Facilities with a Nameplate Capacity Rating of 10,000 kW or less after taking into account any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a Nameplate Capacity Rating of 10,000 kW or less.
- For power purchased from Solar Qualifying Facilities with a Nameplate Capacity Rating of 3,000 kW or less after taking into account any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a Nameplate Capacity Rating of 3,000 kW or less.
- For power purchased from Solar Qualifying Facilities with a Nameplate Capacity Rating of more than 3,000 kW but not greater than 10,000 kW, after taking into account any other electric generating facility using the same motive force owned or controlled by the same person(s) or affiliated person(s) and located at the same site; ***BUT ONLY WITH RESPECT TO CONTRACTING PROCEDURE AND NOT PRICING OPTIONS***.

Owners of these Qualifying Facilities ("**Eligible QFs**") will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility
A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facility or QF
Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Qualifying Electricity
Electricity that meets the requirements of "qualifying electricity" set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

Renewable Qualifying Facility
A Qualifying Facility that generates Qualifying Electricity.

Wind Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using wind as its motive force.

Baseload Renewable Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using any qualifying resource other than wind or solar.

(continued)

Definitions (continued)

Small Power Production Facility
A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

Solar Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using fixed or tracking solar modules.

On-Peak Hours or Peak Hours
On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

Off-Peak Hours
All hours other than On-Peak Hours.

Nameplate Capacity Rating
The maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), and measured at the Point of Interconnection, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant.

Same Site
Two Qualifying Facilities are located on the same site if the generating facilities or equipment providing fuel or motive force associated with the Qualifying Facilities are located within a five-mile radius and the Qualifying Facilities use the same source of energy or motive force to generate electricity.

Person(s)
A natural person or persons or any legal entity.

Affiliated Person(s)
Persons sharing common ownership or management, persons acting jointly or in concert with, or exercising influence over, the policies or actions of another person or persons, or wholly owned subsidiaries.

To the extent a person or affiliated person is a closely held entity, a “look through” rule applies so that project equity held by limited liability companies, trusts, estates, corporations, partnerships, and other similar entities is conserved to be held by the owners of the look through entity.

Two or more Qualifying Facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity so long as they are not owned or operated by the same person(s) or affiliated person(s) of the same person(s) at the

(continued)

Definitions (continued)

time each Qualifying Facility seeks to enter into a power purchase agreement or at any time thereafter.

Two or more Qualifying Facilities within the same five-mile radius will not be considered owned or controlled by the same person(s) or affiliated person(s) if the person(s) or affiliated person(s) in common is a “passive investor” whose ownership interest in the Qualifying Facilities is primarily related to utilizing production tax credits, green tag values and modified accelerated cost recovery system (MACRS) depreciation, and the Qualifying Facilities at issue are “family-owned” or “community-based.”

Shared Interconnection and Infrastructure
Qualifying Facilities otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other Qualifying Facilities qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved standard contract.

Family Owned
After excluding the ownership interest of any passive investor(s), five or fewer individuals that hold at least 50 percent of the project entity, or 15 or fewer individuals that hold at least 90 percent of the project entity. For purposes of counting the number of individuals holding the remaining share (i.e., determining whether there are five or fewer individuals or 15 or fewer individuals), an individual is a natural person. In counting to five or 15, an individual and the individual’s spouses and dependent children will be aggregated and counted as a single individual even if the spouse and/or dependent children also hold equity in the project.

Community-Based
A community-based Qualifying Facility must include participation by a recognized and established organization located within the county of the Qualifying Facility or within 50 miles of the Qualifying Facility that either (i) has a genuine role in developing, or helping to develop, the Qualifying Facility and has a significant continuing role with, or interest in, the Qualifying Facility after it is completed and placed in service; or (ii) is a unit of local government that will not have an equity ownership interest in or exercise any control over the management of the Qualifying Facility and whose only interest is a share of the cash flow from the Qualifying Facility that may not exceed 20 percent.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management, and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract.

Any dispute concerning a QF’s entitlement to the standard rates and standard contract shall be presented to the Commission for resolution. The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 10 or 15-day period in which the utility has the obligation to respond, but

(continued)

Dispute Resolution (continued)

must wait until the 10 or 15-day period has passed. The utility may respond to the complaint within ten days of service. The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The Administrative Law Judge will act as an administrative law judge, not as an arbitrator.

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Pricing Options

1. Standard Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the QF and the Company and will not change during the term of the contract. Subject to the terms and conditions of the standard power purchase agreement, Standard Fixed Avoided Cost Prices are generally available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Standard Fixed Avoided Cost pricing option is available to all QFs. The Standard Fixed Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities reflects integration costs as set forth on pages 7-8.

2. Renewable Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Renewable Qualifying Facility and the Company and will not change during the term of the contract. Subject to the terms and conditions of the standard power purchase agreement, Renewable Fixed Avoided Cost Prices are generally available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Renewable Fixed Avoided Cost pricing option is available only to Renewable Qualifying Facilities. A Renewable Qualifying Facility choosing the Renewable Fixed Avoided Cost pricing option: (a) must cede all Green Tags generated by the facility, as defined in the standard contract, to the Company during the Renewable Resource Deficiency Period identified on page 9 including during any period after the first 15 years of a longer term contract (up to 20 years); and (b) will retain ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page 9.

3. Firm Market Indexed Avoided Cost Prices

Firm Market Index Avoided Cost Prices are available to QFs that contract to deliver firm power. Monthly On-Peak / Off-Peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for On-Peak and Off-Peak prices. The monthly blending matrix is available upon request. The Firm Market Index Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities will reflect integration costs.

4. Non-Firm Market Index Avoided Cost Prices

Non-Firm Market Index Avoided Cost Prices are available to QFs that do not elect to provide firm power. Qualifying Facilities taking this option may request that Company prepare a draft power

(continued)

Pricing Options (continued)

purchase agreement that permits the QF to provide power on an as-available basis. This agreement would differ from the standard power purchase agreement in that it would not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are 93 percent of a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak firm index prices. The monthly blending matrix is available upon request. The Non-Firm Market Index Avoided Cost pricing option is available to all QFs. The Non-Firm Market Index Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities will reflect integration costs.

Third Party Transmission Cost Adjustment

Qualifying Facilities located in discrete load center areas on PacifiCorp's system (also referred to as load "pockets" or load "bubbles") where there is insufficient load to sink additional generation must be exported from that load pocket, transmitted across a third-party transmission system using long-term, firm point-to-point transmission service ("LTF PTP"), and delivered to a different area on PacifiCorp's system where there is sufficient load to sink additional generation. QFs are required to reimburse PacifiCorp for the cost of these third-party system LTF PTP transmission service arrangements, including any associated Ancillary Services. PacifiCorp will procure third-party system LTF PTP and associated Ancillary Services based on the QF's maximum hourly output that is in excess of the load pocket minimum load ("Excess Generation"). Such LTF PTP transmission service and associated Ancillary Services including losses will be procured from the applicable third-party transmission provider consistent with such transmission provider's Open Access Transmission Tariff or comparable pricing schedule for transmission services.

"Ancillary Services," as used in this section, means those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the third-party transmission provider's transmission system in accordance with good utility practice.

The amount and cost of the LTF PTP transmission service and associated Ancillary Services including losses will be subject to periodic updates as provided below and in Exhibit A of this Standard Avoided Cost Rate Schedule, and all terms and conditions will be memorialized in an exhibit to the power purchase agreement ultimately entered into between PacifiCorp and the QF, such exhibit being substantially in the form of Exhibit A of this Standard Avoided Cost Rate Schedule. QFs will have the option to select either option below for such transmission cost adjustments:

Transmission Cost Adjustment Options

1. <u>Direct pass-through of actual costs</u>. The QF will pay all actual costs incurred by PacifiCorp to secure LTF PTP transmission service and associated Ancillary Services from the applicable third-party transmission provider for exporting Excess Generation, as determined by such third-party transmission provider's Open Access Transmission Tariff or comparable pricing schedule for transmission services.

2. <u>Fixed forecast costs</u>. The QF will pay PacifiCorp a monthly fixed amount to secure LTF PTP transmission service and associated Ancillary Services including losses from the applicable third-party transmission provider for exporting Excess Generation. The monthly fixed amount will be determined consistent with Exhibit A of this Standard Avoided Cost Rate Schedule, including Table A of Exhibit A.

(continued)

Monthly Payments

A QF shall select the option of payment at the time of signing the contract under one of the Pricing Options specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Renewable or Standard Fixed Avoided Cost Prices

In accordance with the terms of a contract with a QF, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the renewable or standard fixed prices as provided in this schedule. On-Peak and Off-Peak are defined in the definitions section of this schedule.

Firm Market Indexed and Non-Firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a QF, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. On-Peak and Off-Peak are defined in the definitions section of this schedule.

(This space intentionally left blank)

(continued)

Avoided Cost Prices

Standard Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Base Load QF (1) On-Peak Energy Price	Base Load QF (1) Off-Peak Energy Price	Wind QF (1,2) On-Peak Energy Price	Wind QF (1,2) Off-Peak Energy Price	Wind Integration All hours Energy Charge
	(a)	(b)	(c)	(d)	(e)
2023	13.84	7.59	13.61	7.35	0.23
2024	11.54	7.46	11.34	7.26	0.20
2025	11.41	7.68	11.14	7.41	0.27
2026	5.72	3.73	5.67	3.45	0.29
2027	6.04	4.01	5.96	3.69	0.33
2028	6.22	4.15	6.14	3.81	0.34
2029	6.39	4.28	6.47	4.10	0.18
2030	6.47	4.31	6.57	4.14	0.16
2031	6.69	4.49	6.92	4.44	0.05
2032	6.96	4.71	7.17	4.64	0.07
2033	7.17	4.87	7.44	4.85	0.02
2034	7.40	5.04	7.67	5.03	0.01
2035	7.49	5.09	7.77	5.07	0.02
2036	7.65	5.19	7.94	5.18	0.01
2037	7.95	5.44	8.25	5.44	0.00
2038	8.25	5.69	8.57	5.69	0.00
2039	8.54	5.93	8.86	5.92	0.00
2040	8.88	6.20	9.19	6.19	0.01

(1) Standard Resource Sufficiency Period ends December 31, 2025 and Standard Resource Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (Continued)

Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries During Calendar Year	Fixed Solar QF (1,2)		Tracking Solar QF (1,2)		Solar Integration
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	All hours Energy Charge
	(f)	(g)	(h)	(i)	(j)
2023	13.24	6.98	13.24	6.98	0.61
2024	11.35	7.27	11.35	7.27	0.19
2025	11.29	7.56	11.29	7.56	0.12
2026	4.25	3.64	4.30	3.64	0.09
2027	4.39	3.78	4.44	3.78	0.24
2028	4.55	3.92	4.60	3.92	0.23
2029	4.88	4.24	4.93	4.24	0.04
2030	4.91	4.25	4.96	4.25	0.05
2031	5.14	4.47	5.19	4.47	0.02
2032	5.37	4.68	5.42	4.68	0.03
2033	5.56	4.86	5.62	4.86	0.01
2034	5.75	5.03	5.81	5.03	0.01
2035	5.81	5.07	5.87	5.07	0.01
2036	5.93	5.18	5.99	5.18	0.01
2037	6.20	5.44	6.26	5.44	0.00
2038	6.47	5.69	6.53	5.69	0.00
2039	6.72	5.92	6.78	5.92	0.00
2040	6.98	6.17	7.05	6.17	0.03

(3) Standard Resource Sufficiency Period ends December 31, 2025 and Standard Resource Deficiency Period begins January 1, 2026.

(4) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (continued)

Renewable Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Renewable Base Load QF (1)		Wind QF (1,2)		Wind Integration
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	All hours Energy Charge
	(a)	(b)	(c)	(d)	(e)
2023	13.84	7.59	13.61	7.35	0.23
2024	11.54	7.46	11.34	7.26	0.20
2025	11.41	7.68	11.14	7.41	0.27
2026	5.35	3.16	3.90	2.87	0.29
2027	5.27	3.55	3.75	3.23	0.33
2028	5.32	3.73	3.76	3.39	0.34
2029	5.22	3.70	3.79	3.52	0.18
2030	5.27	3.81	3.84	3.65	0.16
2031	5.29	3.75	3.94	3.70	0.05
2032	5.34	3.95	3.95	3.88	0.07
2033	5.32	4.09	3.95	4.07	0.02
2034	5.43	4.17	4.03	4.15	0.01
2035	5.62	4.18	4.19	4.16	0.02
2036	5.89	4.07	4.43	4.06	0.01
2037	5.89	4.30	4.41	4.30	0.00
2038	5.99	4.42	4.48	4.42	0.00
2039	6.11	4.53	4.57	4.53	0.00
2040	6.37	4.50	4.78	4.48	0.01

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of environmental attributes and the transfer of Green Tags to PacifiCorp, Renewable Sufficiency Period ends December 31, 2025 and Renewable Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (continued)

Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries	Fixed Solar QF (1,2)		Tracking Solar QF (1,2)		Solar Integration
During Calendar Year	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	All hours Energy Charge
	(f)	(g)	(h)	(i)	(j)
2023	12.24	12.24	12.12	12.12	0.61
2024	10.70	10.70	10.62	10.62	0.19
2025	10.69	10.69	10.62	10.62	0.12
2026	2.60	2.60	2.89	2.89	0.09
2027	2.40	2.40	2.70	2.70	0.24
2028	2.42	2.42	2.74	2.74	0.23
2029	2.47	2.47	2.79	2.79	0.04
2030	2.47	2.47	2.80	2.80	0.05
2031	2.45	2.45	2.79	2.79	0.02
2032	2.46	2.46	2.81	2.81	0.03
2033	2.43	2.43	2.79	2.79	0.01
2034	2.47	2.47	2.84	2.84	0.01
2035	2.58	2.58	2.95	2.95	0.01
2036	2.73	2.73	3.10	3.10	0.01
2037	2.70	2.70	3.09	3.09	0.00
2038	2.75	2.75	3.14	3.14	0.00
2039	2.80	2.80	3.20	3.20	0.00
2040	2.92	2.92	3.32	3.32	0.03

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of environmental attributes and the transfer of Green Tags to PacifiCorp, Renewable Sufficiency Period ends December 31, 2025 and Renewable Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the QF owner initiate its request for interconnection at least 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Eligible Qualifying Facilities

APPLICATION: To owners of Eligible QFs (as defined on page 1).

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information

B. Procedures

1. The Company's approved standard form power purchase agreement may be obtained from the Company's website at www.pacificorp.com, or if the QF owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

(continued)

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

2. In order to obtain a project specific draft power purchase agreement the owner of an Eligible QF must provide in writing to the Company the following items:

(a) an executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required;

(b) demonstration of ability to obtain certified QF status prior to commercial operation or initial delivery and, for QFs larger than 1 MW, a Form 556 self-certification of the proposed QF or a FERC order granting an application for certification of the proposed QF is required;

(c) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;

(d) generation technology and other related technology applicable to the site;

(e) proposed site location, including latitude and longitude coordinates for the proposed location;

(f) documentary evidence that the QF has taken meaningful steps to seek control of the proposed site location including but not limited to documentation demonstrating:

i. An ownership of, a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the QF;

ii. An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the QF; or

iii. Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the QF, such as an executed agreement to negotiate an option to lease or purchase the site;

(g) non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable; estimates of the net amount of power to be delivered to the Company's electric system and the 12 x 24 delivery schedule are subject to revision by QF until the earlier of date the QF commences commercial operation and the date on which the power purchase agreement is terminated;

(h) demonstration of eligibility for standard power purchase agreement and pricing under OAR 860-029-0045;

(i) calculation or determination of minimum and maximum annual deliveries;

(j) motive force or fuel plan;

(continued)

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

2. (continued)

(k) proposed scheduled commercial operation date (or initial delivery date for operational QFs) and other significant dates required to complete key milestones; provided that QF owner may not select a scheduled commercial operation date longer than three years after the effective date unless the proposed date is supported by an interconnection study and may in no event select a scheduled commercial operation date more than five years after the effective date of the power purchase agreement;

(l) proposed contract term and pricing option as defined in this Schedule (i.e., standard fixed price, renewable fixed price, firm index, non-firm);

(m) status of interconnection or transmission arrangements;

(n) proposed point of delivery or point(s) of interconnection;

(o) for a QF with battery storage system, a description of the storage design capacity description of the technology used by the battery storage system, storage system duration and net power;

(p) for a QF selecting a scheduled commercial operation date between three and five years after the Effective Date of the standard power purchase agreement pursuant to OAR 860-029-0120(5)(b), a copy of the interconnection study supporting the scheduled commercial operation; and

(q) financial information regarding QF owner to enable the Company to determine whether QF owner will be required to post project development or default security, as applicable, under the terms of the power purchase agreement.

3. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the QF owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Standard Avoided Cost Rate Schedule.

4. After receipt of a draft standard power purchase agreement, the QF owner may submit comments to the Company regarding the draft agreement or request that the Company prepare a final executable power purchase agreement.

5. If the QF owner submits comments to the Company or asks for revisions to the draft standard power purchase agreement, in writing, the Company will, within 10 business days:

(a) notify the QF owner it cannot make the requested changes;

(b) notify the QF owner it does not understand the requested changes or requires additional information; or

(continued)

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

5. (continued)

(c) provide a revised draft power purchase agreement.

However, the Company will respond or provide a revised draft standard power purchase agreement within 15 business days when the QF requests a change to the QF's point of delivery.

6. The process outlined in paragraphs (4) and (5) will continue until both the QF owner and the Company agree to the terms of the draft standard power purchase agreement, i.e., neither the QF owner nor the Company have outstanding issues, corrections, or comments regarding the draft power purchase agreement, after which the QF owner may request a final executable version of the purchase agreement. In such case, the Company will provide a final executable form of the purchase agreement to the QF owner within 10 business days.

7. Upon receipt of the final executable form of the purchase agreement executed by the QF owner, the Company will sign the final executable agreement within five business days; provided that if the QF owner has delayed its execution of the executable form of the purchase agreement for any duration that impacts the applicability of any term or condition in the agreement, then the Company may, instead of signing the agreement within five business days, notify the QF owner that a revised agreement is required and, in such case, will provide a revised draft power purchase agreement to the QF owner within 15 business days thereafter. Following the Company's execution of the final executable form of purchase agreement, a completely executed copy will be returned to the QF owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both

(continued)

II. Process for Negotiating Interconnection Agreements (continued)

transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company’s merchant function (including but not limited to PacifiCorp’s Commercial and Trading Group).

A. Communications

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company’s Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(This space intentionally left blank)

(continued)

Exhibit A to Oregon Standard Avoided Cost Rate Schedule

Transmission Services for Excess Generation

1. No later than seven (7) days after the effective date of the power purchase agreement ("PPA"), PacifiCorp shall submit the request to designate the Qualifying Facility ("QF") as a network resource eligible for network integration transmission service under its Network Integration Transmission Service Agreement with PacifiCorp's transmission function ("DNR Request"). If, in response to PacifiCorp's DNR Request, PacifiCorp is informed by PacifiCorp's transmission function that such network resource designation is contingent on PacifiCorp procuring transmission service from a third-party transmission provider, PacifiCorp shall notify the QF Seller ("Seller") in writing within seven (7) days of receiving the DNR Request transmission study and provide Seller the transmission study or other documentation from PacifiCorp's transmission function that demonstrates the requirement.

2. Within thirty (30) days following Seller's receipt of the notification and supporting materials contemplated in Section 1 above, Seller shall make one of the following elections in writing to PacifiCorp:

   a. Seller shall agree to reimburse PacifiCorp for such third-party transmission service under Option 1 below plus reimburse PacifiCorp for all study costs incurred with the third-party transmission provider; or

   b. Seller shall request PacifiCorp to prepare a proposed Monthly Transmission Rate (as defined below) under Option 2 below for Seller's review plus reimburse PacifiCorp for all study costs incurred with the third-party transmission provider; or

   c. Seller shall terminate the Agreement, and such termination shall not be deemed an event of default under the PPA and neither PacifiCorp nor Seller shall have any further obligations or liability to the other party relating to the PPA.

   If PacifiCorp does not receive Seller's response within forty five (45) days following the delivery of its notification under Section 1 above, Seller shall be deemed to have elected clause 2.c. above and the PPA shall immediately terminate with no further action of either party.

(continued)

3. If Seller timely elects to proceed under Option 1 or Option 2, PacifiCorp will promptly proceed to procure long-term firm, point-to-point transmission service, including ancillary services[1] and losses as applicable ("LTF PTP"), beginning on the scheduled initial delivery date stated in the PPA in an amount determined through the transmission service request process as identified in Section 1 above ("Excess Generation"). Such LTF PTP transmission service will be procured from the applicable third-party transmission provider consistent with such transmission provider's Open Access Transmission Tariff ("OATT") or comparable pricing schedule for transmission services. Such LTF PTP transmission costs incurred by PacifiCorp will be reimbursed by Seller under either Option 1 or Option 2 below, as elected by Seller under Section 2 above. Once either Option 1 or Option 2 is elected by Seller, Seller may not change its election without prior approval of PacifiCorp which approval shall not be unreasonably withheld, conditioned, or delayed subject to commitments under any third-party transmission service application in progress. Seller's obligation to reimburse PacifiCorp for the LTF PTP transmission costs it incurs under either Option 1 or Option 2 below shall not be excused due to any delays in the commercial operation of the QF or the failure of the QF to operate, due to events of force majeure or otherwise.

Option 1 – Direct pass-through of actual costs.

Seller agrees to pay all actual costs incurred by PacifiCorp to secure LTF PTP transmission service from the applicable third-party transmission provider for exporting Excess Generation, as determined by such transmission provider's OATT or comparable pricing schedule for transmission services. If requested by Seller, PacifiCorp will provide within ten (10) business days of the request documentation supporting the actual costs incurred by PacifiCorp and for which PacifiCorp is seeking reimbursement from Seller. Seller compensates PacifiCorp for the actual costs PacifiCorp incurs one month in arrears through a netting of the LTF PTP transmission costs against PacifiCorp's monthly payment for generation under the PPA. Eighteen (18) months prior to each five (5) year anniversary of the start date under the third-party transmission service agreement, PacifiCorp will reevaluate and, if necessary, adjust the amount of LTF PTP transmission capacity necessary to export the Excess Generation.

Option 2 – Fixed forecasted costs.

Within ten (10) business days following PacifiCorp's receipt of Seller's election under clause 2.b. above, PacifiCorp will prepare and provide to Seller the proposed monthly fixed charge (the "Monthly Transmission Rate") that Seller pays to PacifiCorp for the costs it incurs in securing LTF PTP transmission service from the applicable third-party transmission provider for exporting Excess Generation, including workpapers and any other pertinent materials supporting the calculation. Such Monthly Transmission Rate will be determined based on the values provided in Table A of this Oregon Standard Avoided Cost Rate Schedule, as applicable for the relevant third-party transmission provider. If the applicable third-party transmission provider is not identified in Table A, PacifiCorp will prepare a Monthly Transmission Rate using the same methodology as was used to develop the values in Table A using the applicable posted rates of the third-party transmission provider.

[1] Ancillary services are those services that may include balancing services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the third-party transmission provider's transmission system in accordance with good utility practice.

(continued)

3. **Option 2** – **Fixed forecasted costs (continued)**

   Seller has ten (10) business days from the receipt of the proposed Monthly Transmission Rate to inform PacifiCorp whether it (a) elects to pay the transmission charges associated with this Option 2; (b) elects not to pay the transmission charges associated with this Option 2 and elects Option 1 instead; or (c) elects not to pay the transmission charges associated with this Option 2 and elects to terminate the PPA. If PacifiCorp does not receive Seller's response within thirty (30) days following the delivery of the proposed Monthly Transmission Rate from PacifiCorp, Seller shall be deemed to have elected clause (c) of this paragraph and the PPA shall immediately terminate with no further action of either party. Such termination of the PPA under this paragraph shall not be deemed an event of default under the PPA and no party shall have any further obligations or liability to the other party relating to the PPA.

   Seller compensates PacifiCorp for the Monthly Transmission Rate one month in arrears through a netting of the Monthly Transmission Rate against PacifiCorp's monthly payment for generation under the PPA. Eighteen (18) months prior to each five (5) year anniversary of the start date under the third-party transmission service agreement, PacifiCorp will reevaluate and, if necessary, adjust the amount of LTF PTP transmission capacity necessary to export the Excess Generation. In addition, on each five year anniversary of the start date under the transmission service agreement between PacifiCorp and the third-party transmission provider, the Monthly Transmission Rate will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date; provided, however, that any posted rates of an applicable third-party transmission provider not captured in the methodology below but billed to PacifiCorp will also be included in the Monthly Transmission Rate on a prospective basis. If the applicable third-party transmission provider is not identified in Table A, PacifiCorp will adjust the Monthly Transmission Rate using the same methodology as was used to develop the values in Table A using the applicable posted rates of the third-party transmission provider then in effect on such five year anniversary date.

4. If under either Option 1 or Option 2 above, PacifiCorp is notified by the third-party transmission provider that the necessary LTF PTP transmission service request cannot be granted for the term requested, PacifiCorp shall promptly notify Seller and provide the supporting documentation received from the third-party transmission provider. Within thirty (30) days of receipt of such notice under this Section 4, and except as limited below, Seller shall elect one of the following:

   a. Seller will agree to amend the QF PPA to (i) adjust the scheduled initial delivery date and the scheduled commercial operation date, if necessary, to align with the estimated date when LTF PTP transmission service is available; (ii) provide for Seller's reimbursement to PacifiCorp for any study costs it may incur with the third-party transmission provider; (iii) adjust the Monthly Transmission Rate to align with the revised dates under (i), and (iv) adjust the PPA contract price to reflect the change to the scheduled commercial operation date;

   b. Seller will terminate the PPA and such termination by Seller shall not be an event of default under the PPA and no damages or other liabilities under the PPA related to such termination will be owed by one party to the other party.

(continued)

5. **Option 2** – **Fixed forecasted costs (continued)**

If PacifiCorp does not receive Seller's response within forty five (45) days following the date of PacifiCorp's notice to Seller under this Section 4, Seller shall be deemed to have elected clause (b) of this paragraph and the PPA shall immediately terminate with no further action of either Party. Seller may not elect (a) above if the estimated date for availability of LTF PTP transmission service results in an anticipated scheduled commercial operation date that is more than thirty six (36) months following the effective date of the PPA.

(This space intentionally left blank)

(continued)

TABLE A

FIXED MONTHLY THIRD-PARTY TRANSMISSION RATES

Bonneville Power Administration (BPA)

The fixed Monthly Transmission Rate for BPA consists of three components. Components A and B are multiplied by the Excess Generation in kilowatts (kW) as determined by the DNR Request described in Section 1 of this Exhibit. Component C is multiplied by the monthly generation delivery quantity exported over the third-party transmission provider's transmission system to PacifiCorp. The Monthly Transmission Rate is summed across the four components as illustrated in the below formula.

Monthly Transmission Rate ($) = (A + B) * Excess Generation (kW) + C * V (MWh)

Where:

A = Long-Term Firm, Point-to-Point Transmission Service (PTP) ($/kW-month)

B = Scheduling, Control and Dispatch Service (SCD) ($/kW-month)

C = Losses (L) ($/MWh)

Bonneville Power Administration

	A	B	**A+B**	C
Year	Long Term Point-to-Point (PTP)	Scheduling, Control & Dispatch	**Capacity Sub-total**	Losses (1)
	$/KW-Month	$/KW-Month	**$/KW-Month**	$/MWh
2020	$1.533	$0.365	**$1.898**	$0.52
2021	$1.571	$0.374	**$1.945**	$0.54
2022	$1.611	$0.383	**$1.994**	$0.60
2023	$1.651	$0.393	**$2.044**	$0.64
2024	$1.692	$0.403	**$2.095**	$0.72
2025	$1.734	$0.413	**$2.147**	$0.77
2026	$1.778	$0.423	**$2.201**	$0.82
2027	$1.822	$0.434	**$2.256**	$0.82
2028	$1.868	$0.445	**$2.313**	$0.82
2029	$1.915	$0.456	**$2.370**	$0.89
2030	$1.962	$0.467	**$2.430**	$0.92

Notes:

(1) *Losses are calculated by multiplying the BPA losses factor times the Calendar Year Contract Price from the Standard Avoided Cost Rate Schedule times scheduled volume of energy moved across BPA's system in the month. Losses will vary by volume and contract price. Contract price used in table is the standard avoided cost price for wind outside of PacifiCorp's BAA then in effect in Oregon Standard Avoided Cost Rate Schedule. Volume will be monthly volume from PPA times the ratio of the Excess Generation to the total nameplate capacity of the facility. On each five year anniversary of the start date under the transmission service agreement between PacifiCorp and BPA, the Losses will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date.*

(continued)

TABLE A

FIXED MONTHLY THIRD-PARTY TRANSMISSION RATES

Portland General Electric (PGE)

The fixed Monthly Transmission Rate for Portland General consists of four components. Components A, B and C are multiplied by the Excess Generation in kilowatts (kW) as determined by the DNR Request described in Section 1 of this Exhibit. Component D is multiplied by the monthly generation delivery quantity exported over the third-party transmission provider's transmission system to PacifiCorp. The Monthly Transmission Rate is summed across all components as illustrated in the below formula.

Monthly Transmission Rate ($) = (A + B + C) * Excess Generation (kW) + D * V (MWh)

A = Long-Term Firm, Point-to-Point Transmission Service (PTP) ($/kW-month)

B = Scheduling, Control and Dispatch Service (SCD) ($/kW-month)

C = Reactive Supply & Voltage Control Service (RSVC) ($/kW-month)

D = Losses (L) ($/MWh)

Portland General Electric

	A	B	C	**A+B+C**	D
Year	Long Term Point-to-Point (PTP)	Scheduling, Control & Dispatch	Reactive Supply & Voltage Control	**Capacity Sub-total**	Losses (2)
	$/KW-Month	$/KW-Month	$/KW-Month	**$/KW-Month**	$/MWh
2020(3)	$0.523	$0.012	$0.038	**$0.574**	$0.43
2021	$0.536	$0.013	$0.039	**$0.588**	$0.45
2022	$0.549	$0.013	$0.040	**$0.603**	$0.49
2023	$0.563	$0.013	$0.041	**$0.618**	$0.53
2024	$0.577	$0.014	$0.042	**$0.633**	$0.59
2025	$0.592	$0.014	$0.043	**$0.649**	$0.64
2026	$0.607	$0.014	$0.045	**$0.666**	$0.68
2027	$0.622	$0.015	$0.046	**$0.682**	$0.68
2028	$0.637	$0.015	$0.047	**$0.699**	$0.68
2029	$0.653	$0.016	$0.048	**$0.717**	$0.74
2030	$0.669	$0.016	$0.049	**$0.735**	$0.76

Notes:

(2) *Losses are calculated by multiplying the PGE losses factor times the Calendar Year Contract Price from the Standard Avoided Cost Rate Schedule times scheduled volume of energy moved across PGE's system in the month. Losses will vary by volume and contract price. Contract price used in table is the standard avoided cost price for wind outside of PacifiCorp's BAA then in effect in Oregon Standard Avoided Cost Rate Schedule. Volume will be estimated monthly volume from PPA times the ratio of the Excess Generation to the total nameplate capacity of the facility. On each five year anniversary of the start date under the transmission service agreement between PacifiCorp and PGE, the Losses will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date.*

(3) *Components A, B and C are escalated each year by PacifiCorp's acknowledged integrated resource plan escalation rate for third-party transmission service. Component D is not escalated.*

PacifiCorp's

Revised Oregon Standard Avoided Cost Rates Schedule

REDLINE

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

- For power purchased from ~~Base Load~~ Baseload Renewable Qualifying Facilities and Wind Qualifying Facilities with a ~~nameplate capacity~~Nameplate Capacity Rating of 10,000 kW or less ~~or that, together with~~after taking into account any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a ~~nameplate capacity~~Nameplate Capacity Rating of 10,000 kW or less.
- For power purchased ~~Fixed and Tracking~~from Solar Qualifying Facilities with a ~~nameplate capacity~~Nameplate Capacity Rating of 3,000 kW or less ~~or that, together with~~after taking into account any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a ~~nameplate capacity~~Nameplate Capacity Rating of 3,000 kW or less.
- For power purchased from Solar Qualifying Facilities with a Nameplate Capacity Rating of more than 3,000 kW but not greater than 10,000 kW, after taking into account any other electric generating facility using the same motive force owned or controlled by the same person(s) or affiliated person(s) and located at the same site; ***BUT ONLY WITH RESPECT TO CONTRACTING PROCEDURE AND NOT PRICING OPTIONS.***

Owners of these Qualifying Facilities (“**Eligible QFs**”) will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying ~~Facilities~~Facility or QF

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Qualifying Electricity

Electricity that meets the requirements of “qualifying electricity” set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

Renewable Qualifying Facility

A Qualifying Facility that generates Qualifying Electricity.

Wind Qualifying Facility

A Renewable Qualifying Facility that generates Qualifying Electricity using wind as its motive force.

(continued)

Baseload Renewable Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using any qualifying resource other than wind or solar.

Definitions (continued)

Small Power Production Facility
A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

Solar Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using fixed or tracking solar modules.

~~**Definitions (continued)**~~

On-Peak Hours or Peak Hours
On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

Off-Peak Hours
All hours other than On-Peak Hours.

~~**Excess Output**~~
~~Excess Output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-Peak Price as described and calculated under pricing option 4 (Non-Firm Market Index Avoided Cost Price) for all Excess Output.~~

Nameplate Capacity Rating
The maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), and measured at the Point of Interconnection, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant.

Same Site
~~Generating facilities~~ Two Qualifying Facilities are ~~considered to be~~ located ~~at~~ on the same site ~~as the QF for which qualification for the standard rates and standard contract is sought~~ if ~~they are located within a five-mile radius of any~~ the generating facilities or equipment providing fuel or motive force

(continued)

associated with the ~~QF for which qualification for~~Qualifying Facilities are located within a five-mile radius and the Qualifying Facilities use the ~~standard rates and standard contract is sought.~~ same source of energy or motive force to generate electricity.

Person(s) ~~**or Affiliated Person(s)**~~
A natural person or persons or any legal entity.

Affiliated Person(s) ~~or entities~~
Persons sharing common ownership~~,~~ or management ~~or~~, persons acting jointly or in concert with, or exercising influence over, the policies or actions of another person or persons, or wholly owned subsidiaries.

To the extent a person or affiliated person is a closely held entity~~.~~, a "look through" rule applies so that project equity held by limited liability companies, trusts, estates, corporations, partnerships, and other similar entities is conserved to be held by the owners of the look through entity.

Two ~~facilities~~or more Qualifying Facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity~~.~~ so long as they are not owned or operated by the same person(s) or affiliated person(s) of the same person(s) at the

Definitions (continued)
time each Qualifying Facility seeks to enter into a power purchase agreement or at any time thereafter.

Two ~~facilities~~or more Qualifying Facilities within the same five-mile radius will not be ~~held to be~~considered owned or controlled by the same person(s) or affiliated person(s) if ~~such~~ the person(s) or affiliated person(s) in common ~~person or persons~~ is a "passive investor" whose ownership interest in the ~~QF~~Qualifying Facilities is primarily related to utilizing production tax credits, green tag values and modified accelerated cost recovery system (MACRS) depreciation ~~as the primary ownership benefit~~, and the ~~facilities~~Qualifying Facilities at issue are ~~independent~~ "family-owned" or "community-based ~~projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.~~."

Shared Interconnection and Infrastructure
~~QFs~~Qualifying Facilities otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other ~~QFs~~Qualifying Facilities qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved standard contract.
~~**Definitions (continued)**~~

Family Owned

(continued)

After excluding the ownership interest of ~~the~~any passive investor ~~whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit,~~(s), five or fewer individuals ~~own~~that hold at least 50 percent ~~or more of the equity~~ of the project entity, or ~~fifteen~~15 or fewer individuals ~~own~~that hold at least 90 percent ~~or more~~ of the project entity. ~~A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships~~For purposes of counting the number of individuals holding the remaining share (i.e., determining whether there are five or fewer individuals or 15 or ~~other similar entities is considered held by the equity owners of the look through entity. An~~ fewer individuals), an individual is a natural person. In counting to five or ~~fifteen,~~15, an individual and the individual's spouses ~~or~~ and dependent children ~~of an equity owner of the project owner who also have an equity interest are~~will be aggregated and counted as a single individual~~.~~ even if the spouse and/or dependent children also hold equity in the project.

Community-Based

A community ~~project (or a community sponsored project)~~-based Qualifying Facility must ~~have~~include participation by a recognized and established organization located within the county of the ~~project~~Qualifying Facility or within 50 miles of the ~~project~~Qualifying Facility that either (i) has a genuine role in developing, or helping to develop, the ~~project be developed~~Qualifying Facility and ~~must have~~has a significant continuing role with, or interest in, the ~~project~~Qualifying Facility after it is completed and placed in service~~. Many varied and different organizations may qualify under this exception. For example, the community organization could be a church, a school, a water district, an agricultural cooperative, a~~ ; or (ii) is a unit of local government~~, & local utility, a homeowners' association, a charity, a civic organization, and etc.~~

~~After excluding the passive investor whose~~ that will not have an equity ownership ~~interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests~~interest in ~~a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization,~~ or ~~its controlled affiliates; (ii) members~~exercise any control over the management of the ~~sponsoring organization (if it is a membership organization) or owners~~Qualifying Facility and whose only interest is a share of the ~~sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or (v) other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.~~cash flow from the Qualifying Facility that may not exceed 20 percent.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management, and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract.

Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution. The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 10 or 15-day period in which the utility has the obligation to respond, but

Dispute Resolution (continued)

(continued)

must wait until the 10 or 15-day period has passed. The utility may respond to the complaint within ten days of service. The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The Administrative Law Judge will act as an administrative law judge, not as an arbitrator.

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Pricing Options

1. Standard Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the ~~Qualifying Facility~~QF and the Company and will not change during the term of the contract. Subject to the terms and conditions of the standard power purchase agreement, Standard Fixed Avoided Cost Prices are generally available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price.
The Standard Fixed Avoided Cost pricing option is available to all ~~Qualifying Facilities.~~QFs. The Standard Fixed Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities reflects integration costs as set forth on pages ~~6~~ 7-8.

2. Renewable Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Renewable Qualifying Facility and the Company and will not change during the term of the contract. Subject to the terms and conditions of the standard power purchase agreement, Renewable Fixed Avoided Cost Prices are generally available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Renewable Fixed Avoided Cost pricing option is available only to Renewable Qualifying Facilities. A Renewable Qualifying Facility choosing the Renewable Fixed Avoided Cost pricing option: (a) must cede all Green Tags generated by the facility, as defined in the standard contract, to the Company during the Renewable Resource Deficiency Period identified on page ~~8~~9 including during any period after the first 15 years of a longer term contract (up to 20 years); and (b) will retain ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page ~~8~~9.

3. Firm Market Indexed Avoided Cost Prices

Firm Market Index Avoided Cost Prices are available to ~~Qualifying Facilities~~QFs that contract to deliver firm power. Monthly On-Peak / Off-Peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for On-Peak and Off-Peak prices. The monthly blending matrix is available upon request. The Firm Market Index Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities will reflect integration costs.

4. Non-Firm Market Index Avoided Cost Prices

Non-Firm Market Index Avoided Cost Prices are available to ~~Qualifying Facilities~~QFs that do not elect to provide firm power. Qualifying Facilities taking this option ~~will have contracts~~may request that ~~do~~Company prepare a draft power

(continued)

Pricing Options (continued)

purchase agreement that permits the QF to provide power on an as-available basis. This agreement would differ from the standard power purchase agreement in that it would not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are 93 percent of a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak firm index prices. The monthly blending matrix is available upon request. The Non-Firm Market Index Avoided Cost pricing option is available to all ~~Qualifying Facilities.~~QFs. The Non-Firm Market Index Avoided Cost Price for Wind Qualifying Facilities and Solar Qualifying Facilities will reflect integration costs.

Third Party Transmission Cost Adjustment

~~QFs~~Qualifying Facilities located in discrete load center areas on PacifiCorp's system (also referred to as load "pockets" or load "bubbles") where there is insufficient load to sink additional generation must be exported from that load pocket, transmitted across a third-party transmission system using long-term, firm point-to-point transmission service ("LTF PTP"), and delivered to a different area on PacifiCorp's system where there is sufficient load to sink additional generation. QFs are required to reimburse PacifiCorp for the cost of these third-party system LTF PTP transmission service arrangements, including any associated Ancillary Services. PacifiCorp will procure third-party system LTF PTP and associated Ancillary Services based on the QF's maximum hourly output that is in excess of the load pocket minimum load ("Excess Generation"). Such LTF PTP transmission service and associated Ancillary Services including losses will be procured from the applicable third-party transmission provider consistent with such transmission provider's Open Access Transmission Tariff or comparable pricing schedule for transmission services.

"Ancillary Services," as used in this section, means those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the third-party transmission provider's transmission system in accordance with good utility practice.

The amount and cost of the LTF PTP transmission service and associated Ancillary Services including losses will be subject to periodic updates as provided below and in Exhibit A of this Standard Avoided Cost Rate Schedule, and all terms and conditions will be memorialized in an exhibit to the power purchase agreement ultimately entered into between PacifiCorp and the QF, such exhibit being substantially in the form of Exhibit A of this Standard Avoided Cost Rate Schedule. QFs will have the option to select either option below for such transmission cost adjustments:

Transmission Cost Adjustment Options

1. Direct pass-through of actual costs. The QF will pay all actual costs incurred by PacifiCorp to secure LTF PTP transmission service and associated Ancillary Services from the applicable third-party transmission provider for exporting Excess Generation, as determined by such third-party transmission provider's Open Access Transmission Tariff or comparable pricing schedule for transmission services.

2. Fixed forecast costs. The QF will pay PacifiCorp a monthly fixed amount to secure LTF PTP transmission service and associated Ancillary Services including losses from the applicable third-

(continued)

party transmission provider for exporting Excess Generation. The monthly fixed amount will be determined consistent with Exhibit A of this Standard Avoided Cost Rate Schedule, including Table A of Exhibit A.

Monthly Payments

~~A Qualifying Facility~~A QF shall select the option of payment at the time of signing the contract under one of the Pricing Options specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Renewable or Standard Fixed Avoided Cost Prices

In accordance with the terms of a contract with a ~~Qualifying Facility~~QF, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the renewable or standard fixed prices as provided in this schedule. On-Peak and Off-Peak are defined in the definitions section of this schedule.

~~**Monthly Payments (Continued)**~~

Firm Market Indexed and Non-Firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a ~~Qualifying Facility~~QF, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. On-Peak and Off-Peak are defined in the definitions section of this schedule.

(This space intentionally left blank)

(continued)

Avoided Cost Prices

Standard Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Base Load QF (1) On-Peak Energy Price	Base Load QF (1) Off-Peak Energy Price	Wind QF (1,2) On-Peak Energy Price	Wind QF (1,2) Off-Peak Energy Price	Wind Integration All hours Energy Charge
	(a)	(b)	(c)	(d)	(e)
2023	13.84	7.59	13.61	7.35	0.23
2024	11.54	7.46	11.34	7.26	0.20
2025	11.41	7.68	11.14	7.41	0.27
2026	5.72	3.73	5.67	3.45	0.29
2027	6.04	4.01	5.96	3.69	0.33
2028	6.22	4.15	6.14	3.81	0.34
2029	6.39	4.28	6.47	4.10	0.18
2030	6.47	4.31	6.57	4.14	0.16
2031	6.69	4.49	6.92	4.44	0.05
2032	6.96	4.71	7.17	4.64	0.07
2033	7.17	4.87	7.44	4.85	0.02
2034	7.40	5.04	7.67	5.03	0.01
2035	7.49	5.09	7.77	5.07	0.02
2036	7.65	5.19	7.94	5.18	0.01
2037	7.95	5.44	8.25	5.44	0.00
2038	8.25	5.69	8.57	5.69	0.00
2039	8.54	5.93	8.86	5.92	0.00
2040	8.88	6.20	9.19	6.19	0.01

(1) Standard Resource Sufficiency Period ends December 31, 2025 and Standard Resource Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (Continued)

Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries During Calendar Year	Fixed Solar QF (1,2)		Tracking Solar QF (1,2)		Solar Integration
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	All hours Energy Charge
	(f)	(g)	(h)	(i)	(j)
2023	13.24	6.98	13.24	6.98	0.61
2024	11.35	7.27	11.35	7.27	0.19
2025	11.29	7.56	11.29	7.56	0.12
2026	4.25	3.64	4.30	3.64	0.09
2027	4.39	3.78	4.44	3.78	0.24
2028	4.55	3.92	4.60	3.92	0.23
2029	4.88	4.24	4.93	4.24	0.04
2030	4.91	4.25	4.96	4.25	0.05
2031	5.14	4.47	5.19	4.47	0.02
2032	5.37	4.68	5.42	4.68	0.03
2033	5.56	4.86	5.62	4.86	0.01
2034	5.75	5.03	5.81	5.03	0.01
2035	5.81	5.07	5.87	5.07	0.01
2036	5.93	5.18	5.99	5.18	0.01
2037	6.20	5.44	6.26	5.44	0.00
2038	6.47	5.69	6.53	5.69	0.00
2039	6.72	5.92	6.78	5.92	0.00
2040	6.98	6.17	7.05	6.17	0.03

(3) Standard Resource Sufficiency Period ends December 31, 2025 and Standard Resource Deficiency Period begins January 1, 2026.

(4) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (continued)

Renewable Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh)

Deliveries During Calendar Year	Renewable Base Load QF (1)		Wind QF (1,2)		Wind Integration
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	All hours Energy Charge
	(a)	(b)	(c)	(d)	(e)
2023	13.84	7.59	13.61	7.35	0.23
2024	11.54	7.46	11.34	7.26	0.20
2025	11.41	7.68	11.14	7.41	0.27
2026	5.35	3.16	3.90	2.87	0.29
2027	5.27	3.55	3.75	3.23	0.33
2028	5.32	3.73	3.76	3.39	0.34
2029	5.22	3.70	3.79	3.52	0.18
2030	5.27	3.81	3.84	3.65	0.16
2031	5.29	3.75	3.94	3.70	0.05
2032	5.34	3.95	3.95	3.88	0.07
2033	5.32	4.09	3.95	4.07	0.02
2034	5.43	4.17	4.03	4.15	0.01
2035	5.62	4.18	4.19	4.16	0.02
2036	5.89	4.07	4.43	4.06	0.01
2037	5.89	4.30	4.41	4.30	0.00
2038	5.99	4.42	4.48	4.42	0.00
2039	6.11	4.53	4.57	4.53	0.00
2040	6.37	4.50	4.78	4.48	0.01

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of environmental attributes and the transfer of Green Tags to PacifiCorp, Renewable Sufficiency Period ends December 31, 2025 and Renewable Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Avoided Cost Prices (continued)

Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

Deliveries During Calendar Year	Fixed Solar QF (1,2) On-Peak Energy Price	Fixed Solar QF (1,2) Off-Peak Energy Price	Tracking Solar QF (1,2) On-Peak Energy Price	Tracking Solar QF (1,2) Off-Peak Energy Price	Solar Integration All hours Energy Charge
	(f)	(g)	(h)	(i)	(j)
2023	12.24	12.24	12.12	12.12	0.61
2024	10.70	10.70	10.62	10.62	0.19
2025	10.69	10.69	10.62	10.62	0.12
2026	2.60	2.60	2.89	2.89	0.09
2027	2.40	2.40	2.70	2.70	0.24
2028	2.42	2.42	2.74	2.74	0.23
2029	2.47	2.47	2.79	2.79	0.04
2030	2.47	2.47	2.80	2.80	0.05
2031	2.45	2.45	2.79	2.79	0.02
2032	2.46	2.46	2.81	2.81	0.03
2033	2.43	2.43	2.79	2.79	0.01
2034	2.47	2.47	2.84	2.84	0.01
2035	2.58	2.58	2.95	2.95	0.01
2036	2.73	2.73	3.10	3.10	0.01
2037	2.70	2.70	3.09	3.09	0.00
2038	2.75	2.75	3.14	3.14	0.00
2039	2.80	2.80	3.20	3.20	0.00
2040	2.92	2.92	3.32	3.32	0.03

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of environmental attributes and the transfer of Green Tags to PacifiCorp, Renewable Sufficiency Period ends December 31, 2025 and Renewable Deficiency Period begins January 1, 2026.
(2) The avoided cost price has been reduced by wind or solar integration charges applicable to QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system). If wind or solar QF resource is not in PacifiCorp's BAA, prices will be increased by the applicable integration charge.

(continued)

Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the QF owner initiate its request for interconnection at least 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Eligible Qualifying Facilities

APPLICATION: To owners of ~~eligible existing or proposed QFs with a design capacity less than or equal to 10,000 kW for Base Load and Wind QF resources and less than or equal to 3,000 kW for Solar QF resources who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.~~Eligible QFs (as defined on page 1).

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information

B. Procedures

1. The Company's approved ~~generic or~~ standard form power purchase ~~agreements~~agreement may be obtained from the Company's website at www.pacificorp.com, or if the QF owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

(continued)

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

2. In order to obtain a project specific draft power purchase agreement the owner of an Eligible QF must provide in writing to the Company~~, general project information required for~~ the ~~completion of a power purchase agreement, including, but not limited to~~following items:

(a) an executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required;

~~(a)~~(b) demonstration of ability to obtain certified QF status prior to commercial operation or initial delivery and, for QFs larger than 1 MW, a Form 556 self-certification of the proposed QF or a FERC order granting an application for certification of the proposed QF is required;

~~(b)~~ design capacity (MW), station service requirements, and net amount of

(c) power to be delivered to the Company's electric system;

(d) generation technology and other related technology applicable to the site;

(e) proposed site location~~;~~, including latitude and longitude coordinates for the proposed location;

~~(f) schedule of monthly power deliveries;~~

(f) documentary evidence that the QF has taken meaningful steps to seek control of the proposed site location including but not limited to documentation demonstrating:

i. An ownership of, a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the QF;

ii. An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the QF; or

iii. Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the QF, such as an executed agreement to negotiate an option to lease or purchase the site;

(g) non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable; estimates of the net amount of power to be delivered to the Company's electric system and the 12 x 24 delivery schedule are subject to revision by QF until the earlier of date the QF commences commercial operation and the date on which the power purchase agreement is terminated;

(h) demonstration of eligibility for standard power purchase agreement and pricing under OAR 860-029-0045;

~~(g)~~(i) calculation or determination of minimum and maximum annual deliveries;

~~(h)~~(j) motive force or fuel plan;

(continued)

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

2. (continued)

~~(i)~~(k) proposed ~~on-line~~scheduled commercial operation date (or initial delivery date for operational QFs) and other significant dates required to complete ~~the~~key milestones; provided that QF owner may not select a scheduled commercial operation date longer than three years after the effective date unless the proposed date is supported by an interconnection study and may in no event select a scheduled commercial operation date more than five years after the effective date of the power purchase agreement;

~~(j)~~(l) proposed contract term and pricing ~~provisions~~option as defined in this Schedule (i.e., standard fixed price, renewable fixed price, firm index, non-firm);

~~(k)~~(m) status of interconnection or transmission arrangements;

~~(l)~~(n) proposed point of delivery or point(s) of interconnection;

(o) ~~The Company shall provide~~for a ~~draft~~QF with battery storage system, a description of the storage design capacity description of the technology used by the battery storage system, storage system duration and net power;

(p) for a QF selecting a scheduled commercial operation date between three and five years after the Effective Date of the standard power purchase agreement ~~when all~~pursuant to OAR 860-029-0120(5)(b), a copy of the interconnection study supporting the scheduled commercial operation; and

(q) financial information ~~described in Paragraph 2 above has been received in writing from the QF owner.~~ regarding QF owner to enable the Company to determine whether QF owner will be required to post project development or default security, as applicable, under the terms of the power purchase agreement.

3. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the QF owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Standard Avoided Cost Rate Schedule.

4. ~~If the owner desires to proceed with the~~ After receipt of a draft standard power purchase agreement ~~after reviewing the Company's draft power purchase agreement, it~~ , the QF owner may ~~request in writing~~ submit comments to the Company regarding the draft agreement or request that the Company prepare a final ~~draft~~ executable power purchase agreement. ~~In connection with such request, the~~

(continued)

5. If the QF owner ~~must provide the Company with any additional or clarified project information that~~ submits comments to the Company ~~reasonably determines to be necessary~~or asks for revisions to the ~~preparation of a final~~ draft standard power purchase agreement~~. Within 15~~, in writing, the Company will, within 10 business days ~~following receipt of all information~~ :

   (a) notify the QF owner it cannot make the requested ~~by the Company in this paragraph 4, the Company will provide~~ changes;

   ~~(a)~~(b) notify the ~~owner with a final draft power purchase agreement.~~QF owner it does not understand the requested changes or requires additional information; or

~~**I. Process for Completing a Power Purchase Agreement**~~

I. Process for Completing a Power Purchase Agreement

B. Procedures (continued)

~~After reviewing the final~~ 5. (continued)

   (c) provide a revised draft ~~-~~power ~~-~~purchase ~~-~~agreement~~, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals~~.

   However, the Company will respond ~~in~~ or provide a revised draft standard power purchase agreement within 15 business days when the QF requests a change to ~~those comments and proposals.~~ the QF's point of delivery.

~~When both parties are in full agreement as to all terms and conditions~~

6. The process outlined in paragraphs (4) and (5) will continue until both the QF owner and the Company agree to the terms of the draft standard power purchase agreement, i.e., neither the QF owner nor the Company have outstanding issues, corrections, or comments regarding the draft power purchase agreement, after which the ~~Company will prepare and forward to the~~QF owner ~~within 15 business days,~~may request a final executable version of the ~~agreement.~~ purchase agreement. In such case, the Company will provide a final executable form of the purchase agreement to the QF owner within 10 business days.

~~4.~~7. Upon receipt of the final executable form of the purchase agreement executed by the QF owner, the Company will sign the final executable agreement within five business days; provided that if the QF owner has delayed its execution of the executable form of the purchase agreement for any duration that impacts the applicability of any term or condition in the agreement, then the Company

(continued)

may, instead of signing the agreement within five business days, notify the QF owner that a revised agreement is required and, in such case, will provide a revised draft power purchase agreement to the QF owner within 15 business days thereafter. Following the Company's execution ~~a~~ of the final executable form of purchase agreement, a completely executed copy will be returned to the QF owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both

II. Process for Negotiating Interconnection Agreements (continued)

transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

~~**II. Process for Negotiating Interconnection Agreements (continued)**~~

A. Communications ~~(continued)~~

(continued)

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(This space intentionally left blank)

(continued)

Exhibit A to Oregon Standard Avoided Cost Rate Schedule

Transmission Services for Excess Generation

1. No later than seven (7) days after the effective date of the power purchase agreement ("PPA"), PacifiCorp shall submit the request to designate the Qualifying Facility ("QF") as a network resource eligible for network integration transmission service under its Network Integration Transmission Service Agreement with PacifiCorp's transmission function ("DNR Request"). If, in response to PacifiCorp's DNR Request, PacifiCorp is informed by PacifiCorp's transmission function that such network resource designation is contingent on PacifiCorp procuring transmission service from a third-party transmission provider, PacifiCorp shall notify the QF Seller ("Seller") in writing within seven (7) days of receiving the DNR Request transmission study and provide Seller the transmission study or other documentation from PacifiCorp's transmission function that demonstrates the requirement.

2. Within thirty (30) days following Seller's receipt of the notification and supporting materials contemplated in Section 1 above, Seller shall make one of the following elections in writing to PacifiCorp:

   a. Seller shall agree to reimburse PacifiCorp for such third-party transmission service under Option 1 below plus reimburse PacifiCorp for all study costs incurred with the third-party transmission provider; or

   b. Seller shall request PacifiCorp to prepare a proposed Monthly Transmission Rate (as defined below) under Option 2 below for Seller's review plus reimburse PacifiCorp for all study costs incurred with the third-party transmission provider; or

   c. Seller shall terminate the Agreement, and such termination shall not be deemed an event of default under the PPA and neither PacifiCorp nor Seller shall have any further obligations or liability to the other party relating to the PPA.

If PacifiCorp does not receive Seller's response within forty five (45) days following the delivery of its notification under Section 1 above, Seller shall be deemed to have elected clause 2.c. above and the PPA shall immediately terminate with no further action of either party.

(continued)

3. If Seller timely elects to proceed under Option 1 or Option 2, PacifiCorp will promptly proceed to procure long-term firm, point-to-point transmission service, including ancillary services[1] and losses as applicable ("LTF PTP"), beginning on the scheduled initial delivery date stated in the PPA in an amount determined through the transmission service request process as identified in Section 1 above ("Excess Generation"). Such LTF PTP transmission service will be procured from the applicable third-party transmission provider consistent with such transmission provider's Open Access Transmission Tariff ("OATT") or comparable pricing schedule for transmission services. Such LTF PTP transmission costs incurred by PacifiCorp will be reimbursed by Seller under either Option 1 or Option 2 below, as elected by Seller under Section 2 above. Once either Option 1 or Option 2 is elected by Seller, Seller may not change its election without prior approval of PacifiCorp which approval shall not be unreasonably withheld, conditioned, or delayed subject to commitments under any third-party transmission service application in progress. Seller's obligation to reimburse PacifiCorp for the LTF PTP transmission costs it incurs under either Option 1 or Option 2 below shall not be excused due to any delays in the commercial operation of the QF or the failure of the QF to operate, due to events of force majeure or otherwise.

Option 1 – Direct pass-through of actual costs.

Seller agrees to pay all actual costs incurred by PacifiCorp to secure LTF PTP transmission service from the applicable third-party transmission provider for exporting Excess Generation, as determined by such transmission provider's OATT or comparable pricing schedule for transmission services. If requested by Seller, PacifiCorp will provide within ten (10) business days of the request documentation supporting the actual costs incurred by PacifiCorp and for which PacifiCorp is seeking reimbursement from Seller. Seller compensates PacifiCorp for the actual costs PacifiCorp incurs one month in arrears through a netting of the LTF PTP transmission costs against PacifiCorp's monthly payment for generation under the PPA. Eighteen (18) months prior to each five (5) year anniversary of the start date under the third-party transmission service agreement, PacifiCorp will reevaluate and, if necessary, adjust the amount of LTF PTP transmission capacity necessary to export the Excess Generation.

Option 2 – Fixed forecasted costs.

Within ten (10) business days following PacifiCorp's receipt of Seller's election under clause 2.b. above, PacifiCorp will prepare and provide to Seller the proposed monthly fixed charge (the "Monthly Transmission Rate") that Seller pays to PacifiCorp for the costs it incurs in securing LTF PTP transmission service from the applicable third-party transmission provider for exporting Excess Generation, including workpapers and any other pertinent materials supporting the calculation. Such Monthly Transmission Rate will be determined based on the values provided in Table A of this Oregon Standard Avoided Cost Rate Schedule, as applicable for the relevant third-party transmission provider. If the applicable third-party transmission provider is not identified in Table A, PacifiCorp will prepare a Monthly Transmission Rate using the same methodology as was used to develop the values in Table A using the applicable posted rates of the third-party transmission provider.

[1] Ancillary services are those services that may include balancing services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the third-party transmission provider's transmission system in accordance with good utility practice.

(continued)

3. **Option 2** – **Fixed forecasted costs (continued)**

Seller has ten (10) business days from the receipt of the proposed Monthly Transmission Rate to inform PacifiCorp whether it (a) elects to pay the transmission charges associated with this Option 2; (b) elects not to pay the transmission charges associated with this Option 2 and elects Option 1 instead; or (c) elects not to pay the transmission charges associated with this Option 2 and elects to terminate the PPA. If PacifiCorp does not receive Seller's response within thirty (30) days following the delivery of the proposed Monthly Transmission Rate from PacifiCorp, Seller shall be deemed to have elected clause (c) of this paragraph and the PPA shall immediately terminate with no further action of either party. Such termination of the PPA under this paragraph shall not be deemed an event of default under the PPA and no party shall have any further obligations or liability to the other party relating to the PPA.

Seller compensates PacifiCorp for the Monthly Transmission Rate one month in arrears through a netting of the Monthly Transmission Rate against PacifiCorp's monthly payment for generation under the PPA. Eighteen (18) months prior to each five (5) year anniversary of the start date under the third-party transmission service agreement, PacifiCorp will reevaluate and, if necessary, adjust the amount of LTF PTP transmission capacity necessary to export the Excess Generation. In addition, on each five year anniversary of the start date under the transmission service agreement between PacifiCorp and the third-party transmission provider, the Monthly Transmission Rate will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date; provided, however, that any posted rates of an applicable third-party transmission provider not captured in the methodology below but billed to PacifiCorp will also be included in the Monthly Transmission Rate on a prospective basis. If the applicable third-party transmission provider is not identified in Table A, PacifiCorp will adjust the Monthly Transmission Rate using the same methodology as was used to develop the values in Table A using the applicable posted rates of the third-party transmission provider then in effect on such five year anniversary date.

4. If under either Option 1 or Option 2 above, PacifiCorp is notified by the third-party transmission provider that the necessary LTF PTP transmission service request cannot be granted for the term requested, PacifiCorp shall promptly notify Seller and provide the supporting documentation received from the third-party transmission provider. Within thirty (30) days of receipt of such notice under this Section 4, and except as limited below, Seller shall elect one of the following:

   a. Seller will agree to amend the QF PPA to (i) adjust the scheduled initial delivery date and the scheduled commercial operation date, if necessary, to align with the estimated date when LTF PTP transmission service is available; (ii) provide for Seller's reimbursement to PacifiCorp for any study costs it may incur with the third-party transmission provider; (iii) adjust the Monthly Transmission Rate to align with the revised dates under (i), and (iv) adjust the PPA contract price to reflect the change to the scheduled commercial operation date;

   b. Seller will terminate the PPA and such termination by Seller shall not be an event of default under the PPA and no damages or other liabilities under the PPA related to such termination will be owed by one party to the other party.

(continued)

5. **Option 2** – **Fixed forecasted costs (continued)**

If PacifiCorp does not receive Seller's response within forty five (45) days following the date of PacifiCorp's notice to Seller under this Section 4, Seller shall be deemed to have elected clause (b) of this paragraph and the PPA shall immediately terminate with no further action of either Party. Seller may not elect (a) above if the estimated date for availability of LTF PTP transmission service results in an anticipated scheduled commercial operation date that is more than thirty six (36) months following the effective date of the PPA.

(This space intentionally left blank)

(continued)

TABLE A

FIXED MONTHLY THIRD-PARTY TRANSMISSION RATES

Bonneville Power Administration (BPA)

The fixed Monthly Transmission Rate for BPA consists of three components. Components A and B are multiplied by the Excess Generation in kilowatts (kW) as determined by the DNR Request described in Section 1 of this Exhibit. Component C is multiplied by the monthly generation delivery quantity exported over the third-party transmission provider's transmission system to PacifiCorp. The Monthly Transmission Rate is summed across the four components as illustrated in the below formula.

Monthly Transmission Rate ($) = (A + B) * Excess Generation (kW) + C * V (MWh)

Where:

A = Long-Term Firm, Point-to-Point Transmission Service (PTP) ($/kW-month)

B = Scheduling, Control and Dispatch Service (SCD) ($/kW-month)

C = Losses (L) ($/MWh)

Bonneville Power Administration

	A	B	**A+B**	C
Year	Long Term Point-to-Point (PTP)	Scheduling, Control & Dispatch	**Capacity Sub-total**	Losses (1)
	$/KW-Month	$/KW-Month	**$/KW-Month**	$/MWh
2020	$1.533	$0.365	**$1.898**	$0.52
2021	$1.571	$0.374	**$1.945**	$0.54
2022	$1.611	$0.383	**$1.994**	$0.60
2023	$1.651	$0.393	**$2.044**	$0.64
2024	$1.692	$0.403	**$2.095**	$0.72
2025	$1.734	$0.413	**$2.147**	$0.77
2026	$1.778	$0.423	**$2.201**	$0.82
2027	$1.822	$0.434	**$2.256**	$0.82
2028	$1.868	$0.445	**$2.313**	$0.82
2029	$1.915	$0.456	**$2.370**	$0.89
2030	$1.962	$0.467	**$2.430**	$0.92

Notes:

(1) *Losses are calculated by multiplying the BPA losses factor times the Calendar Year Contract Price from the Standard Avoided Cost Rate Schedule times scheduled volume of energy moved across BPA's system in the month. Losses will vary by volume and contract price. Contract price used in table is the standard avoided cost price for wind outside of PacifiCorp's BAA then in effect in Oregon Standard Avoided Cost Rate Schedule. Volume will be monthly volume from PPA times the ratio of the Excess Generation to the total nameplate capacity of the facility. On each five year anniversary of the start date under the transmission service agreement between PacifiCorp and BPA, the Losses will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date.*

(continued)

TABLE A

FIXED MONTHLY THIRD-PARTY TRANSMISSION RATES

Portland General Electric (PGE)

The fixed Monthly Transmission Rate for Portland General consists of four components. Components A, B and C are multiplied by the Excess Generation in kilowatts (kW) as determined by the DNR Request described in Section 1 of this Exhibit. Component D is multiplied by the monthly generation delivery quantity exported over the third-party transmission provider's transmission system to PacifiCorp. The Monthly Transmission Rate is summed across ~~the~~ all components as illustrated in the below formula.

Monthly Transmission Rate ($) = (A + B + C) * Excess Generation (kW) + D * V (MWh)

A = Long-Term Firm, Point-to-Point Transmission Service (PTP) ($/kW-month)

B = Scheduling, Control and Dispatch Service (SCD) ($/kW-month)

C = Reactive Supply & Voltage Control Service (RSVC) ($/kW-month)

D = Losses (L) ($/MWh)

Portland General Electric

	A	B	C	**A+B+C**	D
Year	Long Term Point-to-Point (PTP)	Scheduling, Control & Dispatch	Reactive Supply & Voltage Control	**Capacity Sub-total**	Losses (2)
	$/KW-Month	$/KW-Month	$/KW-Month	**$/KW-Month**	$/MWh
2020(3)	$0.523	$0.012	$0.038	**$0.574**	$0.43
2021	$0.536	$0.013	$0.039	**$0.588**	$0.45
2022	$0.549	$0.013	$0.040	**$0.603**	$0.49
2023	$0.563	$0.013	$0.041	**$0.618**	$0.53
2024	$0.577	$0.014	$0.042	**$0.633**	$0.59
2025	$0.592	$0.014	$0.043	**$0.649**	$0.64
2026	$0.607	$0.014	$0.045	**$0.666**	$0.68
2027	$0.622	$0.015	$0.046	**$0.682**	$0.68
2028	$0.637	$0.015	$0.047	**$0.699**	$0.68
2029	$0.653	$0.016	$0.048	**$0.717**	$0.74
2030	$0.669	$0.016	$0.049	**$0.735**	$0.76

Notes:

(2) Losses are calculated by multiplying the PGE losses factor times the Calendar Year Contract Price from the Standard Avoided Cost Rate Schedule times scheduled volume of energy moved across PGE's system in the month. Losses will vary by volume and contract price. Contract price used in table is the standard avoided cost price for wind outside of PacifiCorp's BAA then in effect in Oregon Standard Avoided Cost Rate Schedule. Volume will be estimated monthly volume from PPA times the ratio of the Excess Generation to the total nameplate capacity of the facility. On each five year anniversary of the start date under the transmission service agreement between PacifiCorp and PGE, the Losses will be adjusted based on the applicable forecasted rates provided in Table A of PacifiCorp's Oregon Standard Avoided Cost Rate Schedule then in effect on such five year anniversary date.

(3) Components A, B and C are escalated each year by PacifiCorp's acknowledged integrated resource plan escalation rate for third-party transmission service. Component D is not escalated.

PGE's

Revised Schedule 201

CLEAN

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

I. PURPOSE

To provide information about Standard Non-Renewable Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA), power purchase prices and price options for power delivered to Portland General Electric Company's (PGE or the Company) service territory by a Qualifying Facility (QF) with nameplate capacity of 10,000 kW (10MW) or less.

II. AVAILABLE

To owners of QFs making sales of electricity to the Company (Seller).

III. APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

IV. DEFINITIONS

A. As-Available Energy means all Net Output delivered to PGE if Seller elected the As-Available Rate.

B. Net Output means all energy and capacity produced by the Facility, less station service, transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any.

C. Community-Based QF means a QF that includes participation by a recognized and established organization located within the county of the qualifying facility or within 50 miles of the qualifying facility that either:

   i. Has a genuine role in developing or helping develop the qualifying facility and has a significant continuing role with, or interest in, the qualifying facility after it is completed and placed in service; or

   ii. Is a unit of local government that will not have an equity ownership interest in or exercise any control over the management of the qualifying facility and whose only interest is a share of the cash flow from the qualifying facility, that may not exceed 20 percent.

D. Family-Based QF means a QF in which, not including the ownership interest of any passive investor(s), five or fewer individuals hold at least 50 percent of the project entity, or fifteen or fewer individuals hold at least 90 percent of the project entity. For purposes of determining whether there are five or fewer individuals or fifteen or fewer individuals, an individual is a natural person. However, notwithstanding the foregoing, an individual, his or her spouse, and his or her dependent children, will be aggregated and counted as a single individual even if the spouse and/or dependent children also hold equity in the project.

SCHEDULE 201 (Continued)

DEFINITIONS (Continued)

E. Renewable Resource Deficiency Period means the period commencing on January 1, 2025, and continuing thereafter.
F. Renewable Resource Sufficiency Period means the period from the current year through to December 31, 2024.
G. Resource Deficiency Period means the period commencing on January 1, 2025, and continuing thereafter.
H. Resource Sufficiency Period means the period from the current year through to December 31, 2024.

I. POWER PURCHASE AND SALE

A Seller may email Qualifying Facilities Contract Administration at Qualifying.Facility@pgn.com to obtain more information about being a Seller or how to enter a Standard PPA under this schedule. A Seller must execute a PPA with the Company prior to delivery of power to the Company.

A. STANDARD PPA

In accordance with terms set forth in this schedule and the Commission's rules as applicable, the Company will purchase Net Output under a Standard PPA from eligible QFs with nameplate capacity of 10,000 kW (10 MW) or less. QFs with a nameplate capacity of 10,000 kW (10 MW) or above are not eligible for a Standard PPA. Delivery of energy by Seller must be at a voltage, phase, frequency, and power factor as specified by the Company.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years from the scheduled commercial operation date as selected by the QF and memorialized in the PPA.

Seller may select a scheduled commercial operation date longer than three years after the effective date only if Seller provides an interconnection study from PGE showing that it will take PGE longer than three years from the effective date of the PPA to complete the required interconnection. In no event shall Seller be permitted to select a scheduled commercial operation date longer than five years after the effective date of the PPA. The scheduled commercial operation date selected by the Seller may be changed under certain circumstances pursuant to the terms of the Standard PPA.

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

SCHEDULE 201 (Continued)

B. NEGOTIATED PPA

Any Seller may elect to negotiate a PPA with the Company pursuant to Schedule 202.

C. AS AVAILABLE PPA

Any Seller may request that PGE prepare a draft power purchase agreement that permits the QF to provide Net Output on an as-available basis.

II. PROCESS FOR REQUESTING AND EXECUTING A STANDARD PPA

Upon receiving a written request from an eligible qualifying facility, PGE will provide a draft Standard PPA after the qualifying facility has provided the following materials in written form:

1. An executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required;

2. Documentary evidence that the qualifying facility has taken meaningful steps to seek site control of the proposed location of the qualifying facility including, but not limited to, documentation demonstrating:
   (a) An ownership of a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the qualifying facility;
   (b) An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the qualifying facility; or
   (c) Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the qualifying facility, such as an executed agreement to negotiate an option to lease or purchase the site.

3. The following information regarding the proposed qualifying facility:
   (a) Demonstration of ability to obtain certified qualifying facility status prior to commercial
   (b) operation (for qualifying facilities larger than 1 MW, a Form 556 self-certification of the proposed qualifying facility or a FERC order granting an application for certification of the proposed qualifying facility is required);
   (c) Demonstration of eligibility for Standard PPA and pricing;
   (d) Design capacity (MW);
   (e) Estimate of station service requirements and net amount of power to be delivered to PGE's electric system;
   (f) Generation technology and other related technology applicable to the site;

SCHEDULE 201 (Continued)

PROCESS FOR REQUESTING AND EXECUTING A STANDARD PPA (Continued)

(g) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable (estimates of the net amount of power to be delivered to PGE's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation) and assumptions made in providing such non-binding estimate;
(h) Motive force or fuel plan;
(i) Proposed scheduled commercial operation date;
(j) Proposed contract term;
(k) Proposed pricing provisions;
(l) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration;
(m) Latitude and longitude of proposed facility and site layout;
(n) For a qualifying facility with battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration;
(o) For a qualifying facility selecting a scheduled commercial operation date between three and five years after the Effective Date of the standard power purchase agreement pursuant to OAR 860-029-0120(5)(b), a copy of the interconnection study from PGE supporting the scheduled commercial operation date; and
(p) Copies of any interconnection agreements that the qualifying facility has executed, any interconnection applications, and any completed interconnection studies.
(q) For an off-system qualifying facility, number and status of any transmission service requests.
(r) Documents showing that the QF has a senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of

a. 'BBB+' or greater from S&P Global Ratings; or
b. "Baa1' or greater from Moody's Investor Services; provided that if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baa1' from S&P Global Ratings or Moody's Investor Services.
c. If a rating from S&P Global Ratings or Moody's Investor Services is not available, the qualifying facility must provide financial documentation that supports an equivalent rating as determined by PGE through its reasonable internal review process and utilizing its credit scoring model. In particular, a QF must provide audited financial statements for the most recent two full years including balance sheets, income statements, statements of cash flow, and accompanying footnotes.

SCHEDULE 201 (Continued)

PROCESS FOR REQUESTING AND EXECUTING A STANDARD PPA (Continued)

When an eligible qualifying facility provides to PGE all information required above, the Company will respond within 15 business days with a draft Standard PPA (Draft PPA), including current standard avoided cost prices as approved by the Commission.

A qualifying facility may submit comments to PGE regarding the Draft PPA or request that PGE prepare a final executable standard power purchase agreement (Final Executable PPA). If a qualifying facility submits comments on the Draft PPA or asks for revisions to the Draft PPA, PGE will within 10 business days: (i) notify the qualifying facility that it cannot make the requested changes; (ii) notify the qualifying facility it does not understand the requested changes or requires additional information; or (iii) provide a revised Draft PPA. If the qualifying facility asks for a change to the Point of Delivery, PGE will have 15 business days to respond or provide a revised Draft PPA. The process outlined above will continue until both the Seller and PGE agree to the terms of the Draft PPA.

After Seller and PGE concur on the terms of the Draft PPA, the Seller may submit a written request for a Final Executable PPA. Within 10 business days of receiving such a request, PGE will provide a Final Executable PPA. Upon receipt of the Final Executable PPA signed by the eligible qualifying facility, PGE will sign the Final Executable PPA within five business days. The terms and conditions in the PPA will not be final and binding until the Final Executable PPA has been executed by both parties.

To determine whether the Seller satisfies the credit requirements of the standard PPA, PGE may request further relevant financial information and the QF shall provide such information within 15 days of the receipt of such request. PGE will evaluate such financial information based on (i) the type of generation resource; (ii) the size of the resource; (iii) the expected energy delivery start date; and (iv) the term of the power purchase agreement. On or before the effective date in the applicable Standard PPA, PGE will inform the Seller whether it has satisfied the credit requirements in the Standard PPA.

III. OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company’s electric system may enter into a Standard PPA with the Company after and making the arrangements necessary for transmission of power to the Company’s system. Seller is responsible for all costs associated with the transmission of power to the Company’s service territory. Seller may not rely on any transmission owned or held by the Company, other than Network Integration Transmission Service on PGE’s System. Off-system QFs will be subject to Exhibit L to the standard PPA that sets forth terms and conditions for payment applicable to off-system QFs.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company’s service territory, the Seller is responsible for the transmission of power at its cost to the Company’s service territory.

SCHEDULE 201 (Continued)

IV. STANDARD POWER PURCHASE AGREEMENT AND PRICES

A. ELIGIBILITY

The Standard PPA pricing will be based on either the Non-Renewable or Renewable Avoided Costs in effect at the time the Final Executable PPA is executed. A QF will be eligible to receive either the Non-Renewable Fixed Price Option or the Renewable Fixed Price Option described below only if the nameplate capacity of the QF does not exceed 3 MW for solar QF projects or 10 MW for all other types of QF projects. A QF that does not meet these eligibility requirements must negotiate prices pursuant to the terms of Schedule 202. Solar QF projects with nameplate capacity that exceed 3 MW but do not exceed 10 MW are eligible for a Standard PPA containing negotiated prices under Schedule 202.

A qualifying facility will be eligible to receive the Non-Renewable Fixed Price Option or the Renewable Fixed Price Option (as appropriate) under the Standard PPA if the nameplate capacity of the qualifying facility, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliate(s), and located at the same site, does not exceed 3 MW for solar qualifying facility projects or 10 MW for all other types of qualifying facility projects.

For purposes of determining eligibility for the Standard PPA, Non-Renewable Fixed Price Option or the Renewable Fixed Price Option, two qualifying facilities are located on the same site if the facilities or equipment providing fuel or motive force associated with the qualifying facilities are located within a five-mile radius and the qualifying facilities use the same source of energy or motive force to generate electricity.

For purposes of this section, a person is a natural person or any legal entity, and affiliate(s) are persons sharing common ownership or management, persons acting jointly or in concert with, or exercising influence over, the policies of another person or persons, or wholly owned subsidiaries. To the extent a person or affiliate is a closely held entity, a "look through" rule applies so that project equity held by limited liability companies, trusts, estates, corporations, partnerships, and other similar entities is considered to be held by the owners of the look through entity.

Two or more qualifying facilities will not be held to be owned or controlled by the same person(s) or affiliate(s) solely because they are developed by a single entity so long as they are not owned or operated by the same person(s) or affiliate(s) of the same person(s) at the time each qualifying facility seeks to enter into a power purchase agreement or at any time thereafter.

Two or more qualifying facilities that otherwise are not owned or operated by the same person(s) or affiliates(s) will not be determined to be a single qualifying facility based on the fact that they have in place a shared interest or agreement regarding interconnection facilities, interconnection-related system upgrades, or any other infrastructure not providing motive force or fuel.

SCHEDULE 201 (Continued)

The qualifying facility seeking a Standard PPA, and other facilities within the same five-mile radius, will not be considered owned or controlled by the same person(s) or affiliate(s) if the person(s) or affiliate(s) in common are passive investors whose ownership interest is primarily for obtaining value related to production tax credits, green tag values, or modified accelerated cost recovery system (MACRS) depreciation, and the qualifying facility and other facilities at issue are Family-Owned or Community-Based qualifying facilities.

B. AVOIDED COST PRICING SUMMARY

The power purchase prices are based on either the Company's Non-Renewable Avoided Costs or Renewable Avoided Costs in effect at the time the PPA is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Non-Renewable Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Non-Renewable Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Non-Renewable Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Non-Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Resource Deficiency Period, the Non-Renewable Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT avoided costs are based on the variable cost of energy plus capitalized energy costs at a 94.01% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates during the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery within the Company's service territory pursuant to a Standard PP.

SCHEDULE 201 (Continued)

AVOIDED COST PRICING SUMMARY (Continued)

Except for As-Available Energy, the Company will pay the Seller during the Fixed Price Period either the On-Peak Non-Renewable Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for Net Output delivered in the On-Peak Period. Except for As-Available Energy, the Company will pay the Seller during the Fixed Price Period either the Off-Peak Non-Renewable Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for Net Output delivered in the Off-Peak Period. For Net Output delivered pursuant to a Standard PPA that is delivered after the Fixed Price Period and during the term of the Standard PPA, the Company will pay the Seller Firm Electric Market Pricing. The Company will pay the Seller the As-Available Rate for all As-Available Energy delivered during the PPA term.

C. NON-RENEWABLE FIXED PRICE OPTION

The Non-Renewable Fixed Price Option is based on Non-Renewable Avoided Costs including forecasted natural gas prices. It is available to all QFs that meet the eligibility requirements identified above.

Prices will be as established at the time the Final Executable PPA is executed and will be equal to the Non-Renewable Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Non-Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Non-Renewable Avoided Costs for the Non-Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 25.00%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 8.50%.

Prices paid to the Seller under the Non-Renewable Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Prices paid to the Seller under the Non-Renewable Fixed Price Option for Solar QFs (Tables 3a and 3b) include a reduction for the solar integration costs in Table 7. However, if the Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 3a and 3b, for a net-zero effect.

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 1a
Avoided Costs
Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	70.99	73.54	153.56	252.44	204.53	82.20	97.49	135.21
2024	133.27	109.83	68.03	61.92	53.76	58.86	175.07	215.84	167.93	81.29	94.54	137.35
2025	54.43	54.34	52.97	49.95	49.80	50.78	51.57	51.80	51.61	52.09	54.47	56.86
2026	58.95	57.53	54.71	51.01	50.95	51.59	52.22	52.37	52.17	52.62	54.25	56.69
2027	58.61	57.36	54.53	51.35	51.22	51.61	52.14	52.36	52.25	52.91	55.17	57.95
2028	59.13	58.02	55.29	51.35	51.32	51.82	52.44	52.77	52.77	53.89	55.95	60.07
2029	52.30	52.41	50.89	50.01	50.11	50.21	50.29	50.40	50.51	50.84	51.67	51.78
2030	52.57	52.69	51.79	50.92	51.01	51.12	51.21	51.32	51.42	52.02	52.86	52.96
2031	53.45	53.55	53.45	52.55	52.66	52.75	52.84	52.96	53.06	54.00	55.08	55.19
2032	55.86	55.97	56.28	55.33	55.44	55.54	55.64	55.77	55.90	56.23	57.22	57.34
2033	58.06	57.20	58.92	57.58	57.51	57.79	57.86	57.86	58.02	58.41	59.17	59.02
2034	60.12	59.78	58.07	57.04	57.15	57.26	57.37	57.49	57.60	57.97	59.06	59.18
2035	59.32	59.13	58.24	57.22	57.33	57.44	57.54	57.65	57.77	58.16	59.18	59.30
2036	58.80	58.16	57.73	56.76	56.86	56.96	57.04	57.15	57.26	57.56	58.48	58.58
2037	61.14	58.40	57.52	56.56	56.66	56.76	56.85	56.95	57.05	57.28	58.25	58.35
2038	61.12	59.73	58.53	57.59	57.69	57.78	57.89	57.99	58.08	58.32	59.45	59.55
2039	61.61	61.38	60.89	60.09	60.10	60.22	60.34	60.44	60.54	61.77	63.17	63.31
2040	66.56	66.50	66.31	65.37	65.49	65.95	66.15	66.29	66.41	68.44	70.13	70.30
2041	73.28	73.40	71.35	70.33	70.49	70.66	70.83	71.01	71.13	72.27	73.96	74.15
2042	77.55	78.52	72.87	71.97	72.19	72.51	72.83	72.72	72.70	73.96	74.66	75.03
2043	78.20	77.29	74.15	73.40	73.46	73.53	73.69	73.86	74.07	74.32	76.36	76.60
2044	80.59	80.14	74.51	73.92	73.76	74.10	74.03	74.22	74.75	76.60	66.92	67.33
2045	71.03	76.76	75.98	74.90	75.45	75.49	75.35	75.62	75.75	76.35	78.34	78.73
2046	81.68	81.36	78.44	77.58	77.68	77.84	77.95	78.19	78.31	78.97	81.14	81.37
2047	85.81	84.83	82.31	81.63	81.67	81.72	81.97	82.12	82.33	83.59	86.69	86.84
2048	90.17	86.71	85.28	84.64	84.69	84.76	85.01	85.18	85.37	87.75	92.15	92.32

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 1b
Avoided Costs
Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	58.76	43.46	69.97	101.57	92.39	74.05	83.22	109.72
2024	108.81	90.46	59.88	55.80	43.57	43.57	79.25	111.36	84.34	60.90	75.17	109.83
2025	28.12	28.02	26.66	23.63	23.48	24.47	25.25	25.49	25.29	25.77	28.16	30.55
2026	32.10	30.68	27.86	24.16	24.09	24.74	25.37	25.51	25.32	25.77	27.40	29.83
2027	31.21	29.96	27.13	23.95	23.81	24.21	24.73	24.95	24.84	25.51	27.77	30.55
2028	31.16	30.06	27.33	23.39	23.36	23.85	24.47	24.80	24.81	25.93	27.99	32.11
2029	23.77	23.87	22.36	21.47	21.57	21.68	21.75	21.87	21.98	22.30	23.14	23.24
2030	23.45	23.57	22.66	21.80	21.89	22.00	22.09	22.20	22.30	22.90	23.74	23.84
2031	23.73	23.84	23.74	22.83	22.95	23.03	23.13	23.24	23.35	24.28	25.36	25.47
2032	25.73	25.83	26.14	25.20	25.31	25.40	25.51	25.64	25.76	26.09	27.09	27.20
2033	27.12	26.25	27.97	26.63	26.56	26.85	26.92	26.91	27.07	27.47	28.22	28.07
2034	28.44	28.10	26.39	25.35	25.47	25.58	25.69	25.80	25.92	26.29	27.38	27.50
2035	27.09	26.91	26.01	24.99	25.10	25.21	25.31	25.42	25.54	25.93	26.96	27.07
2036	26.02	25.38	24.94	23.98	24.08	24.18	24.26	24.36	24.48	24.78	25.70	25.80
2037	27.58	24.83	23.96	23.00	23.10	23.19	23.29	23.38	23.49	23.71	24.68	24.78
2038	26.87	25.48	24.28	23.34	23.44	23.53	23.64	23.74	23.83	24.07	25.20	25.30
2039	26.65	26.43	25.94	25.14	25.15	25.26	25.39	25.49	25.58	26.82	28.22	28.36
2040	30.89	30.83	30.64	29.70	29.83	30.29	30.48	30.62	30.74	32.77	34.47	34.63
2041	36.88	37.01	34.95	33.93	34.10	34.26	34.43	34.61	34.73	35.87	37.56	37.75
2042	40.41	41.38	35.72	34.83	35.04	35.36	35.69	35.58	35.55	36.82	37.52	37.89
2043	40.30	39.39	36.24	35.50	35.55	35.62	35.78	35.95	36.17	36.41	38.46	38.69
2044	42.04	41.58	35.95	35.36	35.20	35.55	35.47	35.66	36.19	38.04	28.37	28.77
2045	31.43	37.16	36.38	35.30	35.85	35.89	35.75	36.02	36.15	36.74	38.74	39.13
2046	41.40	41.08	38.16	37.30	37.40	37.56	37.67	37.91	38.02	38.69	40.86	41.08
2047	44.70	43.73	41.20	40.52	40.57	40.61	40.86	41.01	41.23	42.48	45.58	45.73
2048	48.35	44.89	43.47	42.83	42.87	42.95	43.19	43.36	43.55	45.93	50.34	50.50

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 2a
Avoided Costs
Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	70.64	73.19	153.21	252.09	204.18	81.86	97.15	134.86
2024	132.92	109.47	67.68	61.56	53.41	58.51	174.71	215.49	167.58	80.93	94.18	137.00
2025	43.23	43.13	41.77	38.74	38.60	39.58	40.37	40.60	40.40	40.88	43.27	45.66
2026	47.52	46.10	43.28	39.58	39.51	40.16	40.79	40.93	40.74	41.19	42.82	45.25
2027	46.94	45.70	42.86	39.69	39.55	39.95	40.47	40.69	40.58	41.24	43.51	46.29
2028	47.22	46.12	43.39	39.45	39.42	39.91	40.53	40.86	40.87	41.99	44.05	48.17
2029	40.15	40.26	38.74	37.86	37.96	38.06	38.14	38.25	38.37	38.69	39.53	39.63
2030	40.17	40.29	39.39	38.53	38.61	38.72	38.81	38.92	39.02	39.62	40.46	40.56
2031	40.80	40.90	40.80	39.90	40.01	40.10	40.19	40.31	40.41	41.35	42.43	42.54
2032	43.03	43.13	43.45	42.50	42.61	42.71	42.81	42.94	43.06	43.40	44.39	44.51
2033	44.89	44.02	45.74	44.40	44.34	44.62	44.69	44.68	44.84	45.24	45.99	45.85
2034	46.64	46.29	44.58	43.55	43.66	43.77	43.89	44.00	44.12	44.49	45.57	45.70
2035	45.60	45.41	44.52	43.50	43.61	43.72	43.82	43.93	44.05	44.44	45.46	45.58
2036	44.84	44.20	43.77	42.80	42.90	43.00	43.09	43.19	43.30	43.60	44.53	44.62
2037	46.85	44.11	43.24	42.28	42.37	42.47	42.56	42.66	42.77	42.99	43.96	44.06
2038	46.53	45.15	43.95	43.01	43.11	43.20	43.31	43.41	43.50	43.74	44.87	44.97
2039	46.73	46.50	46.01	45.21	45.22	45.34	45.46	45.56	45.66	46.89	48.29	48.43
2040	51.37	51.31	51.12	50.18	50.31	50.77	50.96	51.11	51.23	53.26	54.95	55.12
2041	57.78	57.91	55.85	54.84	55.00	55.16	55.34	55.51	55.63	56.78	58.46	58.65
2042	61.74	62.71	57.06	56.16	56.37	56.70	57.02	56.91	56.88	58.15	58.85	59.22
2043	62.07	61.16	58.01	57.26	57.32	57.39	57.55	57.72	57.93	58.18	60.23	60.46
2044	64.18	63.72	58.09	57.50	57.35	57.69	57.61	57.80	58.33	60.18	50.51	50.92
2045	54.17	59.91	59.12	58.05	58.59	58.63	58.49	58.76	58.89	59.49	61.48	61.87
2046	64.53	64.22	61.29	60.44	60.53	60.69	60.80	61.04	61.16	61.82	63.99	64.22
2047	68.31	67.33	64.81	64.13	64.17	64.22	64.47	64.62	64.83	66.09	69.19	69.34
2048	72.37	68.91	67.48	66.84	66.89	66.96	67.20	67.37	67.56	69.94	74.35	74.51

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 2b
Avoided Costs
Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	58.41	43.12	69.62	101.22	92.05	73.70	82.87	109.38
2024	108.46	90.11	59.53	55.45	43.22	43.22	78.89	111.00	83.99	60.55	74.82	109.47
2025	27.76	27.66	26.30	23.27	23.12	24.11	24.89	25.13	24.93	25.41	27.80	30.19
2026	31.74	30.31	27.49	23.79	23.73	24.37	25.00	25.15	24.95	25.40	27.03	29.47
2027	30.83	29.59	26.75	23.57	23.44	23.83	24.36	24.58	24.47	25.13	27.39	30.18
2028	30.78	29.68	26.94	23.01	22.98	23.47	24.09	24.42	24.43	25.55	27.61	31.72
2029	23.38	23.48	21.96	21.08	21.18	21.28	21.36	21.47	21.59	21.91	22.75	22.85
2030	23.05	23.17	22.27	21.40	21.49	21.60	21.69	21.80	21.90	22.50	23.34	23.44
2031	23.33	23.43	23.33	22.43	22.54	22.63	22.72	22.83	22.94	23.88	24.96	25.06
2032	25.31	25.42	25.73	24.78	24.89	24.99	25.10	25.22	25.35	25.68	26.67	26.79
2033	26.69	25.83	27.55	26.21	26.14	26.42	26.49	26.49	26.65	27.04	27.80	27.65
2034	28.01	27.67	25.95	24.92	25.03	25.15	25.26	25.37	25.49	25.86	26.95	27.07
2035	26.65	26.47	25.57	24.55	24.66	24.77	24.87	24.98	25.10	25.49	26.51	26.63
2036	25.57	24.93	24.49	23.53	23.63	23.73	23.81	23.91	24.03	24.33	25.25	25.35
2037	27.12	24.37	23.50	22.54	22.64	22.73	22.83	22.92	23.03	23.25	24.23	24.32
2038	26.40	25.02	23.82	22.87	22.97	23.07	23.17	23.27	23.36	23.60	24.73	24.83
2039	26.18	25.95	25.46	24.66	24.67	24.79	24.91	25.01	25.10	26.34	27.74	27.88
2040	30.40	30.34	30.15	29.21	29.34	29.80	29.99	30.14	30.25	32.28	33.98	34.14
2041	36.38	36.51	34.45	33.44	33.60	33.76	33.93	34.11	34.23	35.37	37.06	37.25
2042	39.90	40.87	35.22	34.32	34.53	34.86	35.18	35.07	35.04	36.31	37.01	37.38
2043	39.78	38.87	35.73	34.98	35.04	35.10	35.26	35.43	35.65	35.89	37.94	38.17
2044	41.51	41.05	35.42	34.83	34.68	35.02	34.94	35.13	35.66	37.51	27.84	28.25
2045	30.89	36.62	35.84	34.76	35.31	35.35	35.21	35.48	35.61	36.20	38.20	38.59
2046	40.85	40.53	37.61	36.75	36.85	37.01	37.11	37.36	37.47	38.14	40.30	40.53
2047	44.14	43.16	40.64	39.96	40.00	40.05	40.30	40.45	40.66	41.92	45.02	45.17
2048	47.78	44.32	42.89	42.25	42.30	42.37	42.62	42.79	42.98	45.36	49.76	49.92

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 3a Avoided Costs Fixed Price Option for Solar QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	69.55	72.10	152.12	251.00	203.08	80.76	96.05	133.77
2024	131.80	108.36	66.56	60.45	52.29	57.39	173.60	214.37	166.46	79.82	93.07	135.88
2025	32.32	32.23	30.86	27.84	27.69	28.67	29.46	29.69	29.50	29.98	32.36	34.75
2026	36.39	34.97	32.14	28.45	28.38	29.03	29.66	29.80	29.61	30.06	31.69	34.12
2027	35.58	34.34	31.50	28.33	28.19	28.59	29.11	29.33	29.22	29.88	32.15	34.93
2028	35.63	34.53	31.79	27.86	27.83	28.32	28.94	29.27	29.28	30.39	32.46	36.57
2029	28.32	28.43	26.91	26.03	26.13	26.23	26.31	26.42	26.54	26.86	27.70	27.80
2030	28.10	28.22	27.32	26.45	26.54	26.65	26.74	26.85	26.95	27.55	28.39	28.49
2031	28.48	28.58	28.48	27.58	27.69	27.78	27.87	27.99	28.09	29.03	30.11	30.22
2032	30.53	30.63	30.95	30.00	30.11	30.21	30.31	30.44	30.56	30.90	31.89	32.01
2033	32.06	31.19	32.91	31.57	31.51	31.79	31.86	31.86	32.01	32.41	33.17	33.02
2034	33.51	33.16	31.45	30.42	30.53	30.65	30.76	30.87	30.99	31.36	32.45	32.57
2035	32.24	32.05	31.16	30.14	30.25	30.36	30.46	30.57	30.69	31.08	32.10	32.22
2036	31.25	30.61	30.17	29.21	29.31	29.41	29.49	29.60	29.71	30.01	30.93	31.03
2037	32.94	30.19	29.32	28.36	28.46	28.55	28.65	28.75	28.85	29.07	30.05	30.15
2038	32.34	30.96	29.76	28.81	28.91	29.01	29.11	29.21	29.30	29.54	30.67	30.77
2039	32.24	32.01	31.52	30.72	30.73	30.85	30.97	31.07	31.17	32.40	33.80	33.94
2040	36.58	36.53	36.34	35.40	35.52	35.98	36.18	36.32	36.44	38.47	40.16	40.33
2041	42.69	42.82	40.76	39.75	39.91	40.07	40.25	40.42	40.54	41.69	43.37	43.56
2042	46.34	47.31	41.66	40.76	40.98	41.30	41.62	41.51	41.49	42.75	43.45	43.82
2043	46.35	45.44	42.30	41.55	41.61	41.68	41.84	42.01	42.22	42.47	44.51	44.75
2044	48.19	47.73	42.10	41.51	41.36	41.70	41.62	41.81	42.34	44.19	34.52	34.93
2045	37.76	43.50	42.71	41.64	42.18	42.22	42.08	42.35	42.48	43.08	45.07	45.46
2046	47.83	47.52	44.59	43.74	43.83	44.00	44.10	44.34	44.46	45.12	47.29	47.52
2047	51.27	50.29	47.77	47.09	47.13	47.18	47.43	47.58	47.79	49.05	52.15	52.29
2048	55.03	51.57	50.14	49.50	49.55	49.62	49.86	50.03	50.22	52.60	57.01	57.17

SCHEDULE 201 (Continued)

NON-RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 3b Avoided Costs Fixed Price Option for Solar QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	57.32	42.02	68.53	100.13	90.95	72.61	81.78	108.28
2024	107.34	88.99	58.41	54.33	42.10	42.10	77.78	109.89	82.87	59.43	73.70	108.36
2025	26.62	26.52	25.16	22.13	21.98	22.97	23.75	23.99	23.79	24.27	26.66	29.05
2026	30.57	29.15	26.32	22.63	22.56	23.21	23.84	23.98	23.79	24.24	25.87	28.30
2027	29.64	28.40	25.57	22.39	22.25	22.65	23.17	23.39	23.28	23.94	26.21	28.99
2028	29.57	28.47	25.73	21.80	21.76	22.26	22.88	23.21	23.21	24.33	26.40	30.51
2029	22.14	22.24	20.73	19.84	19.94	20.05	20.13	20.24	20.35	20.68	21.51	21.61
2030	21.79	21.91	21.00	20.14	20.23	20.34	20.43	20.54	20.64	21.24	22.08	22.18
2031	22.04	22.14	22.04	21.14	21.25	21.34	21.43	21.55	21.65	22.59	23.67	23.78
2032	24.00	24.10	24.42	23.47	23.58	23.67	23.78	23.91	24.03	24.37	25.36	25.48
2033	25.35	24.49	26.21	24.87	24.80	25.08	25.15	25.15	25.31	25.70	26.46	26.31
2034	26.64	26.30	24.59	23.55	23.67	23.78	23.89	24.00	24.12	24.49	25.58	25.70
2035	25.26	25.07	24.18	23.15	23.26	23.37	23.48	23.59	23.71	24.10	25.12	25.23
2036	24.14	23.50	23.07	22.10	22.20	22.30	22.38	22.49	22.60	22.90	23.82	23.92
2037	25.66	22.92	22.05	21.09	21.18	21.28	21.38	21.47	21.58	21.80	22.77	22.87
2038	24.91	23.53	22.33	21.39	21.49	21.58	21.69	21.79	21.88	22.12	23.25	23.35
2039	24.66	24.44	23.95	23.14	23.16	23.27	23.40	23.50	23.59	24.83	26.22	26.37
2040	28.85	28.79	28.61	27.66	27.79	28.25	28.45	28.59	28.71	30.74	32.43	32.60
2041	34.80	34.93	32.87	31.86	32.02	32.18	32.36	32.53	32.65	33.80	35.48	35.68
2042	38.29	39.26	33.61	32.71	32.92	33.25	33.57	33.46	33.43	34.70	35.40	35.77
2043	38.14	37.23	34.08	33.33	33.39	33.46	33.62	33.79	34.00	34.25	36.30	36.53
2044	39.83	39.37	33.74	33.15	33.00	33.34	33.27	33.45	33.99	35.83	26.16	26.57
2045	29.18	34.91	34.13	33.05	33.59	33.64	33.50	33.77	33.90	34.49	36.49	36.88
2046	39.10	38.79	35.86	35.01	35.10	35.26	35.37	35.61	35.73	36.39	38.56	38.79
2047	42.36	41.38	38.86	38.18	38.22	38.27	38.52	38.67	38.88	40.14	43.24	43.38
2048	45.96	42.50	41.07	40.43	40.48	40.56	40.80	40.97	41.16	43.54	47.94	48.11

SCHEDULE 201 (Continued)

D. RENEWABLE FIXED PRICE OPTION

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210 and that satisfy the eligibility requirements identified above.

Prices will be as established at the time the Final Executable PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Seller will retain and transfer Environmental Attributes consistent with the terms and conditions of the Standard PPA.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 25.00%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 8.50%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE’s Balancing Authority Area as contemplated in the Commission’s Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Prices paid to the Seller under the Renewable Fixed Price Option for Solar QFs (Tables 6a and 6b) include a reduction for the solar integration costs in Table 7. However, if the Solar QF is outside of PGE’s Balancing Authority Area as contemplated in the Commission’s Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 6a and 6b.

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 4a												
Renewable Avoided Costs												
Renewable Fixed Price Option for Base Load QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	70.99	73.54	153.56	252.44	204.53	82.20	97.49	135.21
2024	133.27	109.83	68.03	61.92	53.76	58.86	175.07	215.84	167.93	81.29	94.54	137.35
2025	70.54	62.76	48.89	46.86	44.15	45.85	84.41	97.94	82.04	53.29	57.69	71.90
2026	71.99	64.05	49.89	47.82	45.06	46.79	86.14	99.95	83.72	54.38	58.87	73.37
2027	73.46	65.36	50.91	48.80	45.98	47.74	87.91	102.00	85.44	55.49	60.07	74.87
2028	74.84	66.59	51.89	49.74	46.87	48.67	89.54	103.88	87.03	56.55	61.21	76.27
2029	76.50	68.06	53.02	50.82	47.89	49.72	91.54	106.22	88.98	57.79	62.56	77.97
2030	78.07	69.46	54.11	51.86	48.87	50.74	93.42	108.40	90.80	58.98	63.84	79.57
2031	79.67	70.88	55.22	52.92	49.87	51.78	95.33	110.62	92.66	60.18	65.15	81.20
2032	80.97	72.03	56.08	53.75	50.64	52.59	96.91	112.46	94.19	61.14	66.19	82.53
2033	82.97	73.82	57.50	55.12	51.93	53.92	99.28	115.20	96.50	62.68	67.85	84.56
2034	84.77	75.43	58.78	56.35	53.10	55.13	101.42	117.66	98.57	64.06	69.34	86.39
2035	86.40	76.87	59.88	57.40	54.08	56.15	103.39	119.96	100.49	65.27	70.66	88.06
2036	87.92	78.22	60.93	58.40	55.02	57.13	105.20	122.07	102.25	66.41	71.89	89.60
2037	89.98	80.05	62.36	59.77	56.32	58.48	107.67	124.93	104.65	67.97	73.58	91.70
2038	91.82	81.69	63.64	61.00	57.47	59.68	109.88	127.49	106.79	69.36	75.09	93.58
2039	93.70	83.37	64.94	62.25	58.65	60.90	112.13	130.10	108.98	70.78	76.63	95.50
2040	95.46	84.94	66.19	63.45	59.79	62.07	114.21	132.50	111.01	72.13	78.08	97.29
2041	97.58	86.82	67.63	64.82	61.08	63.42	116.77	135.49	113.49	73.71	79.80	99.45
2042	99.58	88.60	69.02	66.15	62.33	64.72	119.16	138.26	115.82	75.22	81.43	101.49
2043	101.62	90.41	70.43	67.51	63.61	66.04	121.60	141.09	118.19	76.77	83.10	103.57
2044	103.40	91.99	71.66	68.68	64.72	67.20	123.74	143.57	120.26	78.11	84.55	105.38
2045	105.95	94.28	73.47	70.43	66.37	68.90	126.76	147.06	123.21	80.07	86.67	107.98
2046	107.99	96.08	74.85	71.74	67.60	70.19	129.23	149.94	125.60	81.58	88.31	110.07
2047	110.21	98.05	76.38	73.21	68.98	71.63	131.88	153.02	128.18	83.25	90.12	112.32
2048	112.14	99.77	77.71	74.49	70.18	72.87	134.19	155.71	130.43	84.71	91.70	114.29

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 4b
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	58.76	43.46	69.97	101.57	92.39	74.05	83.22	109.72
2024	108.81	90.46	59.88	55.80	43.57	43.57	79.25	111.36	84.34	60.90	75.17	109.83
2025	36.11	30.02	19.87	18.52	14.46	14.46	26.30	36.96	27.99	20.21	24.95	36.45
2026	36.85	30.64	20.28	18.90	14.76	14.76	26.84	37.71	28.56	20.62	25.46	37.19
2027	37.60	31.26	20.69	19.29	15.06	15.06	27.39	38.49	29.15	21.05	25.98	37.96
2028	38.27	31.82	21.06	19.63	15.32	15.32	27.87	39.17	29.67	21.42	26.44	38.63
2029	39.16	32.56	21.55	20.08	15.68	15.68	28.52	40.08	30.36	21.92	27.05	39.53
2030	39.96	33.22	21.99	20.49	16.00	16.00	29.11	40.90	30.98	22.37	27.61	40.34
2031	40.78	33.91	22.44	20.91	16.33	16.33	29.70	41.74	31.61	22.83	28.17	41.16
2032	41.50	34.51	22.84	21.28	16.62	16.62	30.23	42.48	32.17	23.23	28.67	41.89
2033	42.47	35.31	23.37	21.78	17.01	17.01	30.93	43.47	32.92	23.77	29.34	42.87
2034	43.34	36.03	23.85	22.23	17.35	17.35	31.57	44.36	33.60	24.26	29.94	43.75
2035	44.23	36.77	24.34	22.68	17.71	17.71	32.21	45.26	34.28	24.75	30.55	44.64
2036	45.01	37.42	24.77	23.08	18.02	18.02	32.78	46.07	34.89	25.19	31.10	45.43
2037	46.06	38.29	25.35	23.62	18.44	18.44	33.55	47.14	35.70	25.78	31.82	46.49
2038	47.00	39.08	25.87	24.10	18.82	18.82	34.23	48.10	36.43	26.31	32.47	47.44
2039	47.97	39.88	26.40	24.60	19.21	19.21	34.93	49.09	37.18	26.85	33.14	48.41
2040	48.81	40.58	26.86	25.03	19.55	19.55	35.55	49.96	37.84	27.32	33.72	49.27
2041	49.95	41.53	27.49	25.62	20.00	20.00	36.38	51.12	38.72	27.96	34.51	50.42
2042	50.97	42.38	28.05	26.14	20.41	20.41	37.13	52.17	39.51	28.53	35.22	51.45
2043	52.02	43.25	28.63	26.68	20.83	20.83	37.89	53.24	40.32	29.11	35.94	52.51
2044	52.94	44.01	29.13	27.15	21.20	21.20	38.56	54.18	41.04	29.63	36.57	53.44
2045	54.17	45.04	29.81	27.78	21.69	21.69	39.45	55.44	41.99	30.32	37.42	54.68
2046	55.28	45.96	30.42	28.35	22.14	22.14	40.26	56.58	42.85	30.94	38.19	55.80
2047	56.41	46.90	31.05	28.93	22.59	22.59	41.09	57.74	43.73	31.57	38.97	56.94
2048	57.41	47.73	31.59	29.44	22.99	22.99	41.81	58.76	44.50	32.13	39.66	57.95

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 5a
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	70.64	73.19	153.21	252.09	204.18	81.86	97.15	134.86
2024	132.92	109.47	67.68	61.56	53.41	58.51	174.71	215.49	167.58	80.93	94.18	137.00
2025	59.34	51.56	37.69	35.66	32.95	34.64	73.21	86.74	70.84	42.09	46.48	60.69
2026	60.56	52.62	38.46	36.39	33.63	35.35	74.71	88.52	72.29	42.95	47.44	61.94
2027	61.80	53.69	39.25	37.14	34.32	36.08	76.24	90.33	73.77	43.83	48.41	63.21
2028	62.93	54.69	39.99	37.84	34.97	36.76	77.63	91.98	75.12	44.65	49.31	64.37
2029	64.35	55.92	40.87	38.67	35.74	37.57	79.40	94.07	76.83	45.64	50.41	65.82
2030	65.67	57.06	41.71	39.46	36.47	38.34	81.02	96.00	78.40	46.58	51.45	67.17
2031	67.02	58.23	42.57	40.27	37.22	39.13	82.68	97.97	80.01	47.53	52.50	68.55
2032	68.14	59.20	43.25	40.92	37.81	39.75	84.08	99.63	81.36	48.31	53.36	69.69
2033	69.79	60.64	44.33	41.94	38.76	40.75	86.11	102.02	83.32	49.50	54.67	71.38
2034	71.28	61.94	45.30	42.86	39.61	41.64	87.93	104.17	85.09	50.57	55.85	72.91
2035	72.68	63.15	46.16	43.68	40.36	42.43	89.67	106.24	86.77	51.55	56.94	74.34
2036	73.96	64.26	46.97	44.44	41.07	43.17	91.25	108.11	88.29	52.45	57.93	75.64
2037	75.69	65.77	48.07	45.48	42.03	44.19	93.38	110.64	90.36	53.68	59.29	77.42
2038	77.24	67.11	49.06	46.42	42.89	45.10	95.29	112.91	92.21	54.78	60.51	79.00
2039	78.82	68.49	50.06	47.37	43.77	46.02	97.25	115.22	94.10	55.91	61.75	80.62
2040	80.27	69.76	51.01	48.26	44.60	46.89	99.02	117.32	95.82	56.95	62.90	82.10
2041	82.09	71.32	52.14	49.33	45.58	47.92	101.27	119.99	98.00	58.22	64.30	83.96
2042	83.77	72.78	53.20	50.34	46.52	48.91	103.35	122.45	100.00	59.41	65.62	85.68
2043	85.48	74.27	54.29	51.37	47.47	49.91	105.46	124.96	102.05	60.63	66.96	87.43
2044	86.98	75.58	55.24	52.27	48.30	50.78	107.32	127.16	103.85	61.69	68.14	88.97
2045	89.10	77.42	56.62	53.57	49.51	52.05	109.90	130.20	106.35	63.21	69.81	91.13
2046	90.85	78.93	57.70	54.59	50.45	53.04	112.08	132.80	108.45	64.43	71.16	92.92
2047	92.71	80.55	58.88	55.71	51.48	54.12	114.38	135.52	110.68	65.75	72.62	94.82
2048	94.33	81.96	59.91	56.68	52.38	55.07	116.39	137.90	112.62	66.90	73.90	96.49

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 5b												
Renewable Avoided Costs												
Renewable Fixed Price Option for Wind QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	58.41	43.12	69.62	101.22	92.05	73.70	82.87	109.38
2024	108.46	90.11	59.53	55.45	43.22	43.22	78.89	111.00	83.99	60.55	74.82	109.47
2025	35.75	29.66	19.51	18.16	14.10	14.10	25.94	36.60	27.63	19.85	24.59	36.09
2026	36.48	30.27	19.91	18.53	14.39	14.39	26.47	37.35	28.20	20.26	25.09	36.83
2027	37.23	30.89	20.32	18.91	14.68	14.68	27.01	38.11	28.77	20.67	25.60	37.58
2028	37.89	31.43	20.68	19.24	14.94	14.94	27.49	38.78	29.28	21.04	26.06	38.25
2029	38.77	32.17	21.16	19.69	15.29	15.29	28.13	39.69	29.97	21.53	26.66	39.14
2030	39.57	32.83	21.59	20.10	15.60	15.60	28.71	40.50	30.58	21.97	27.21	39.94
2031	40.38	33.50	22.04	20.51	15.92	15.92	29.30	41.33	31.21	22.42	27.77	40.76
2032	41.09	34.09	22.43	20.87	16.20	16.20	29.81	42.06	31.76	22.81	28.26	41.48
2033	42.05	34.89	22.95	21.36	16.58	16.58	30.51	43.04	32.50	23.35	28.92	42.44
2034	42.91	35.60	23.42	21.79	16.92	16.92	31.13	43.92	33.16	23.82	29.51	43.31
2035	43.79	36.33	23.90	22.24	17.27	17.27	31.77	44.82	33.84	24.31	30.11	44.20
2036	44.56	36.97	24.32	22.63	17.57	17.57	32.33	45.62	34.44	24.74	30.65	44.98
2037	45.60	37.83	24.89	23.16	17.98	17.98	33.09	46.68	35.24	25.32	31.36	46.03
2038	46.53	38.61	25.40	23.64	18.35	18.35	33.76	47.63	35.97	25.84	32.00	46.97
2039	47.49	39.40	25.92	24.12	18.73	18.73	34.46	48.61	36.70	26.37	32.66	47.94
2040	48.33	40.09	26.38	24.55	19.06	19.06	35.06	49.47	37.35	26.83	33.23	48.78
2041	49.45	41.03	26.99	25.12	19.50	19.50	35.88	50.62	38.22	27.46	34.01	49.92
2042	50.47	41.87	27.54	25.63	19.90	19.90	36.62	51.66	39.00	28.02	34.71	50.94
2043	51.50	42.73	28.11	26.16	20.31	20.31	37.37	52.72	39.80	28.60	35.42	51.99
2044	52.41	43.48	28.60	26.62	20.67	20.67	38.03	53.65	40.51	29.10	36.04	52.91
2045	53.63	44.50	29.27	27.24	21.15	21.15	38.91	54.90	41.45	29.78	36.88	54.14
2046	54.73	45.41	29.87	27.80	21.58	21.58	39.71	56.03	42.30	30.39	37.64	55.25
2047	55.85	46.34	30.48	28.37	22.03	22.03	40.52	57.17	43.17	31.01	38.41	56.38
2048	56.84	47.16	31.02	28.87	22.42	22.42	41.24	58.18	43.93	31.56	39.09	57.38

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 6a
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	69.55	72.10	152.12	251.00	203.08	80.76	96.05	133.77
2024	131.80	108.36	66.56	60.45	52.29	57.39	173.60	214.37	166.46	79.82	93.07	135.88
2025	48.43	40.65	26.78	24.75	22.05	23.74	62.30	75.83	59.93	31.18	35.58	49.79
2026	49.42	41.48	27.33	25.26	22.50	24.22	63.58	77.39	61.16	31.82	36.31	50.81
2027	50.44	42.33	27.89	25.78	22.96	24.72	64.88	78.97	62.42	32.47	37.05	51.85
2028	51.34	43.10	28.40	26.24	23.38	25.17	66.04	80.38	63.53	33.06	37.72	52.78
2029	52.52	44.09	29.04	26.84	23.91	25.74	67.57	82.24	65.00	33.81	38.58	53.99
2030	53.60	44.99	29.64	27.39	24.40	26.27	68.95	83.93	66.33	34.51	39.37	55.10
2031	54.70	45.91	30.25	27.95	24.90	26.81	70.36	85.65	67.69	35.21	40.18	56.23
2032	55.64	46.70	30.75	28.42	25.31	27.25	71.58	87.13	68.86	35.81	40.86	57.19
2033	56.96	47.81	31.50	29.11	25.93	27.92	73.28	89.19	70.49	36.67	41.84	58.55
2034	58.15	48.81	32.17	29.73	26.48	28.51	74.80	91.04	71.96	37.44	42.72	59.78
2035	59.32	49.79	32.80	30.32	27.00	29.07	76.31	92.88	73.41	38.19	43.58	60.98
2036	60.36	50.66	33.37	30.84	27.47	29.58	77.65	94.52	74.70	38.86	44.34	62.05
2037	61.78	51.85	34.16	31.57	28.12	30.28	79.47	96.73	76.45	39.77	45.38	63.50
2038	63.04	52.91	34.86	32.22	28.70	30.90	81.10	98.71	78.01	40.58	46.31	64.80
2039	64.33	54.00	35.57	32.88	29.28	31.53	82.76	100.73	79.61	41.42	47.26	66.13
2040	65.49	54.97	36.22	33.48	29.82	32.10	84.24	102.53	81.04	42.16	48.11	67.32
2041	67.00	56.23	37.05	34.24	30.50	32.83	86.18	104.90	82.91	43.13	49.21	68.87
2042	68.37	57.39	37.81	34.94	31.12	33.51	87.95	107.05	84.61	44.01	50.22	70.28
2043	69.77	58.56	38.58	35.66	31.76	34.19	89.75	109.24	86.34	44.92	51.25	71.72
2044	70.99	59.59	39.25	36.28	32.31	34.79	91.33	111.17	87.86	45.70	52.15	72.98
2045	72.68	61.01	40.20	37.16	33.10	35.64	93.49	113.79	89.94	46.80	53.40	74.71
2046	74.15	62.23	41.00	37.89	33.75	36.34	95.38	116.10	91.75	47.73	54.47	76.22
2047	75.66	63.51	41.84	38.67	34.44	37.08	97.33	118.47	93.63	48.71	55.58	77.78
2048	76.99	64.62	42.57	39.34	35.04	37.73	99.05	120.56	95.28	49.56	56.55	79.14

SCHEDULE 201 (Continued)

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 6b
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	57.32	42.02	68.53	100.13	90.95	72.61	81.78	108.28
2024	107.34	88.99	58.41	54.33	42.10	42.10	77.78	109.89	82.87	59.43	73.70	108.36
2025	34.61	28.52	18.37	17.02	12.96	12.96	24.80	35.46	26.49	18.71	23.45	34.95
2026	35.32	29.10	18.75	17.37	13.22	13.22	25.31	36.18	27.03	19.09	23.93	35.66
2027	36.04	29.70	19.13	17.72	13.50	13.50	25.83	36.92	27.59	19.48	24.42	36.39
2028	36.68	30.22	19.47	18.03	13.73	13.73	26.28	37.57	28.07	19.83	24.84	37.03
2029	37.53	30.93	19.92	18.46	14.05	14.05	26.89	38.45	28.73	20.29	25.43	37.90
2030	38.30	31.56	20.33	18.83	14.34	14.34	27.45	39.24	29.32	20.71	25.95	38.68
2031	39.09	32.21	20.75	19.22	14.64	14.64	28.01	40.04	29.92	21.13	26.48	39.47
2032	39.78	32.78	21.11	19.56	14.89	14.89	28.50	40.75	30.44	21.50	26.94	40.16
2033	40.71	33.54	21.61	20.02	15.24	15.24	29.17	41.70	31.16	22.01	27.58	41.10
2034	41.54	34.23	22.05	20.43	15.55	15.55	29.77	42.56	31.80	22.46	28.14	41.95
2035	42.39	34.93	22.50	20.84	15.87	15.87	30.37	43.43	32.45	22.92	28.72	42.81
2036	43.14	35.55	22.90	21.21	16.15	16.15	30.91	44.19	33.02	23.32	29.22	43.56
2037	44.15	36.38	23.43	21.71	16.53	16.53	31.63	45.22	33.79	23.87	29.91	44.58
2038	45.05	37.12	23.91	22.15	16.87	16.87	32.28	46.15	34.48	24.35	30.52	45.49
2039	45.97	37.88	24.40	22.61	17.21	17.21	32.94	47.10	35.19	24.85	31.14	46.42
2040	46.78	38.55	24.83	23.00	17.51	17.51	33.52	47.92	35.81	25.29	31.69	47.24
2041	47.88	39.45	25.41	23.54	17.93	17.93	34.31	49.05	36.64	25.88	32.43	48.34
2042	48.86	40.26	25.93	24.02	18.29	18.29	35.01	50.05	37.40	26.41	33.10	49.33
2043	49.86	41.09	26.47	24.52	18.67	18.67	35.73	51.08	38.16	26.95	33.78	50.35
2044	50.73	41.81	26.93	24.94	18.99	18.99	36.35	51.97	38.83	27.42	34.37	51.23
2045	51.92	42.79	27.56	25.53	19.44	19.44	37.20	53.19	39.74	28.07	35.17	52.43
2046	52.99	43.66	28.13	26.05	19.84	19.84	37.97	54.28	40.56	28.64	35.89	53.50
2047	54.07	44.56	28.70	26.59	20.25	20.25	38.74	55.39	41.39	29.23	36.63	54.60
2048	55.02	45.34	29.20	27.05	20.60	20.60	39.42	56.37	42.11	29.74	37.27	55.56

SCHEDULE 201 (Continued)

WIND INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2023	0.35	1.44
2024	0.35	1.47
2025	0.36	1.50
2026	0.37	1.53
2027	0.37	1.56
2028	0.38	1.59
2029	0.39	1.63
2030	0.40	1.66
2031	0.41	1.69
2032	0.41	1.73
2033	0.42	1.76
2034	0.43	1.80
2035	0.44	1.84
2036	0.45	1.87
2037	0.46	1.91
2038	0.47	1.95
2039	0.48	1.99
2040	0.49	2.03
2041	0.50	2.07
2042	0.51	2.12
2043	0.52	2.16
2044	0.53	2.21
2045	0.54	2.25
2046	0.55	2.30
2047	0.56	2.34
2048	0.57	2.39

E. AS-AVAILABLE RATE

The As-Available Rate is based on the Avoided Energy Cost for surplus energy at the time of delivery. The As-Available Rate is equal to the Avoided Energy Cost. The Company will purchase As-Available Energy at the As-Available Rate. QFs seeking an As-Available Rate should request that PGE prepare a draft power purchase agreement that permits the QF to provide Net Output on an as-available basis.

SCHEDULE 201 (Continued)

Avoided Energy Cost:

The Avoided Energy Cost means eighty-two and four tenths percent (82.4%) of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices. Each day's index prices will reflect the relative proportions of peak hours and off-peak hours in the month as follows:

$$.824 * \left(\sum_{X=1}^{n} \{(\text{ICE Mid-C Physical Peak (bilateral) Avg}_X * \text{applicable peak index hours for day}) + (\text{ICE Mid-C Physical Off-Peak (bilateral) Avg}_X * \text{applicable off-peak index hours for day})\} / (n*24)\right)$$

where n = number of days in the month

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the applicable day-ahead Intercontinental Exchange ("ICE") Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) indices representative of the OTC market for WSPP Schedule-C physical Firm Energy transactions at the Mid-C trading hub. Product details for the Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) are found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

V. MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail customer account will be charged $10.00 per month.

VI. INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a Generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Concluded)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's System must comply with all requirements for interconnection as established pursuant to Commission rule or order, in the Company's Rules and Regulations (Rule C), or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

VII. DISPUTE RESOLUTION

Upon request, the qualifying facility will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the qualifying facility in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the qualifying facility meets the above-described criteria for entitlement to the Standard PPA.

The QF may present disputes to the Commission for resolution using the process outlined in the applicable statutes and Commission rules.

However, the QF may not file such a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract during any 15-day or 10-day period in which the utility has the obligation to respond, but must wait until the 15-day or 10-day period has passed.

PGE's

Revised Schedule 201

REDLINE

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

I. PURPOSE

To provide information about Standard Non-Renewable Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA)~~ and Negotiated PPAs~~, power purchase prices and price options for power delivered to Portland General Electric Company's (PGE or the Company) service territory by a Qualifying Facility (QF) ~~to the Company~~ with nameplate capacity of 10,000 kW (10MW) or less.

II. AVAILABLE

To owners of QFs making sales of electricity to the Company ~~in the State of Oregon~~ (Seller).

III. APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

IV. DEFINITIONS

A. As-Available Energy means all Net Output delivered to PGE if Seller elected the As-Available Rate.

B. Net Output means all energy and capacity produced by the Facility, less station service, transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any.

C. Community-Based QF means a QF that includes participation by a recognized and established organization located within the county of the qualifying facility or within 50 miles of the qualifying facility that either:

   i. Has a genuine role in developing or helping develop the qualifying facility and has a significant continuing role with, or interest in, the qualifying facility after it is completed and placed in service; or
   ii. Is a unit of local government that will not have an equity ownership interest in or exercise any control over the management of the qualifying facility and whose only interest is a share of the cash flow from the qualifying facility, that may not exceed 20 percent.

D. Family-Based QF means a QF in which, not including the ownership interest of any passive investor(s), five or fewer individuals hold at least 50 percent of the project entity, or fifteen or fewer individuals hold at least 90 percent of the project entity. For purposes of determining whether there are five or fewer individuals or fifteen or fewer individuals, an individual is a natural person. However, notwithstanding the foregoing, an individual, his or her spouse, and his or her dependent children, will be aggregated and counted as a single individual even if the spouse and/or dependent children also hold equity in the project.

SCHEDULE 201 (Continued)

DEFINITIONS (Continued)

E. Renewable Resource Deficiency Period means the period commencing on January 1, 2025, and continuing thereafter.
F. Renewable Resource Sufficiency Period means the period from the current year through to December 31, 2024.
G. Resource Deficiency Period means the period commencing on January 1, 2025, and continuing thereafter.
H. Resource Sufficiency Period means the period from the current year through to December 31, 2024.

~~**ESTABLISHING CREDITWORTHINESS**~~

~~The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.~~

I. POWER PURCHASE AND SALE ~~INFORMATION~~

A Seller may ~~call the Power Production Coordinator at (503) 464-8000~~email Qualifying Facilities Contract Administration at Qualifying.Facility@pgn.com to obtain more information about being a Seller or how to enter a Standard PPA~~apply for service~~ under this schedule. A Seller must execute a PPA with the Company prior to delivery of power to the Company.

A. STANDARD PPA

In accordance with terms set forth in this schedule and the Commission's rules as applicable, the Company will purchase Net Output under a Standard PPA from eligible QFs with nameplate capacity of 10,000 kW (10 MW) or less. QFs with a nameplate capacity of 10,000 kW (10 MW) or above are not eligible for a Standard PPA. ~~any energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.~~ Delivery of energy by Seller must be at a voltage, phase, frequency, and power factor as specified by the Company.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years from the scheduled commercial operation date as selected by the QF and memorialized in the PPA.

~~A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.~~

Seller may select a scheduled commercial operation date longer than three years after the effective date only if Seller provides an interconnection study from PGE showing that it will take PGE longer than three years from the effective date of the PPA to complete the required interconnection. In no event shall Seller be permitted to select a scheduled commercial operation date longer than five years after the effective date of the PPA. The scheduled commercial operation date selected by the Seller may be changed under certain circumstances pursuant to the terms of the Standard PPA.

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

SCHEDULE 201 (Continued)

~~B.~~ NEGOTIATED PPA

Any Seller may elect to negotiate a PPA with the Company pursuant to Schedule 202.

C. AS AVAILABLE PPA

Any Seller may request that PGE prepare a draft power purchase agreement that permits the QF to provide Net Output on an as-available basis.

~~**STANDARD PPA (Nameplate capacity of 10 MW or less)**~~

~~A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:~~

~~Standard In-System Non-Variable Power Purchase Agreement~~
~~Standard Off-System Non-Variable Power Purchase Agreement~~
~~Standard In-System Variable Power Purchase Agreement~~
~~Standard Off-System Variable Power Purchase Agreement~~
~~Standard Renewable In-System Non-Variable Power Purchase Agreement~~
~~Standard Renewable Off-System Non-Variable Power Purchase Agreement~~
~~Standard Renewable In-System Variable Power Purchase Agreement~~
~~Standard Renewable Off-System Variable Power Purchase Agreement~~

~~The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.~~

~~**GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA**~~

~~To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.~~

~~When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.~~

~~The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.~~

~~When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.~~

II. PROCESS FOR REQUESTING AND EXECUTING A STANDARD PPA

Upon receiving a written request from an eligible qualifying facility, PGE will provide a draft Standard PPA after the qualifying facility has provided the following materials in written form:

1. An executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required;

2. Documentary evidence that the qualifying facility has taken meaningful steps to seek site control of the proposed location of the qualifying facility including, but not limited to, documentation demonstrating:
   (a) An ownership of a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the qualifying facility;
   (b) An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the qualifying facility; or
   (c) Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the qualifying facility, such as an executed agreement to negotiate an option to lease or purchase the site.

3. The following information regarding the proposed qualifying facility:
   (a) Demonstration of ability to obtain certified qualifying facility status prior to commercial
   (b) operation (for qualifying facilities larger than 1 MW, a Form 556 self-certification of the proposed qualifying facility or a FERC order granting an application for certification of the proposed qualifying facility is required);
   (c) Demonstration of eligibility for Standard PPA and pricing;
   (d) Design capacity (MW);
   (e) Estimate of station service requirements and net amount of power to be delivered to PGE's electric system;
   (f) Generation technology and other related technology applicable to the site;
   (g) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable (estimates of the net amount of power to be delivered to PGE's electric system and the 12 x 24 delivery schedule are subject to revision until the date the qualifying facility commences commercial operation) and assumptions made in providing such non-binding estimate;
   (h) Motive force or fuel plan;
   (i) Proposed scheduled commercial operation date;
   (j) Proposed contract term;
   (k) Proposed pricing provisions;
   (l) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration;
   (m) Latitude and longitude of proposed facility and site layout;
   (n) For a qualifying facility with battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration;
   (o) For a qualifying facility selecting a scheduled commercial operation date between three and five years after the Effective Date of the standard power

purchase agreement pursuant to OAR 860-029-0120(5)(b), a copy of the interconnection study from PGE supporting the scheduled commercial operation date; and

(p) Copies of any interconnection agreements that the qualifying facility has executed, any interconnection applications, and any completed interconnection studies.

(q) For an off-system qualifying facility, number and status of any transmission service requests.

(r) Documents showing that the QF has a senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of

a. 'BBB+' or greater from S&P Global Ratings; or

b. "Baa1' or greater from Moody's Investor Services; provided that if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baa1' from S&P Global Ratings or Moody's Investor Services.

c. If a rating from S&P Global Ratings or Moody's Investor Services is not available, the qualifying facility must provide financial documentation that supports an equivalent rating as determined by PGE through its reasonable internal review process and utilizing its credit scoring model. In particular, a QF must provide audited financial statements for the most recent two full years including balance sheets, income statements, statements of cash flow, and accompanying footnotes.

SCHEDULE 201 (Continued)

PROCESS FOR REQUESTING AND EXECUTING A STANDARD PPA (Continued)

When an eligible qualifying facility provides to PGE all information required above, the Company will respond within 15 business days with a draft Standard PPA (Draft PPA), including current standard avoided cost prices as approved by the Commission.

A qualifying facility may submit comments to PGE regarding the Draft PPA or request that PGE prepare a final executable standard power purchase agreement (Final Executable PPA). If a qualifying facility submits comments on the Draft PPA or asks for revisions to the Draft PPA, PGE will within 10 business days: (i) notify the qualifying facility that it cannot make the requested changes; (ii) notify the qualifying facility it does not understand the requested changes or requires additional information; or (iii) provide a revised Draft PPA. If the qualifying facility asks for a change to the Point of Delivery, PGE will have 15 business days to respond or provide a revised Draft PPA. The process outlined above will continue until both the Seller and PGE agree to the terms of the Draft PPA.

After Seller and PGE concur on the terms of the Draft PPA, the Seller may submit a written request for a Final Executable PPA. Within 10 business days of receiving such a request, PGE will provide a Final Executable PPA. Upon receipt of the Final Executable PPA signed by the eligible qualifying facility, PGE will sign the Final Executable PPA within five business days. The terms and conditions in the PPA will not be final and binding until the Final Executable PPA has been executed by both parties.

To determine whether the Seller satisfies the credit requirements of the standard PPA, PGE may request further relevant financial information and the QF shall provide such information within 15 days of the receipt of such request. PGE will evaluate such financial information based on (i) the type of generation resource; (ii) the size of the resource; (iii) the expected energy delivery start date; and (iv) the term of the power purchase agreement. On or before the effective date in the applicable Standard PPA, PGE will inform the Seller whether it has satisfied the credit requirements in the Standard PPA.

III. OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a Standard PPA with the Company after ~~following the applicable Standard or Negotiated PPA guidelines~~ and making the arrangements necessary for transmission of power to the Company's system. Seller is responsible for all costs associated with the transmission of power to the Company's service territory. Seller may not rely on any transmission owned or held by the Company, other than Network Integration Transmission Service on PGE's System. Off-system QFs will be subject to Exhibit L to the standard PPA that sets forth terms and conditions for payment applicable to off-system QFs.

~~**TRANSMISSION AGREEMENTS**~~

~~If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.~~

SCHEDULE 201 (Continued)

IV.~~BASIS FOR~~ STANDARD POWER PURCHASE AGREEMENT AND PRICES

A. ~~AVOIDED COST SUMMARY~~ELIGIBILITY

~~The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."~~

~~Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.~~

~~ON-PEAK PERIOD~~

~~The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.~~

~~OFF-PEAK PERIOD~~

~~The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.~~

~~Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 94.01% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.~~

~~Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.~~

~~PRICING FOR STANDARD PPA~~

~~Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour.~~

~~ELIGIBILITY REQUIREMENTS TO RECEIVE THE STANDARD FIXED PRICE OPTION OR THE RENEWABLE FIXED PRICE OPTION~~

The Standard PPA pricing will be based on either the ~~Standard~~ Non-Renewable or Renewable Avoided Costs in effect at the time the Final Executable PPA ~~agreement~~ is executed. A QF will be eligible to receive either the ~~Standard~~ Non-Renewable Fixed Price Option or the Renewable Fixed Price Option described below only if the nameplate capacity of the QF does not exceed 3 MW for solar QF projects or 10 MW for all other types of QF projects. A QF that does not meet these eligibility requirements must negotiate prices pursuant to the terms of Schedule 202. Solar QF projects with nameplate capacity that exceed 3 MW but do not exceed 10 MW are eligible for a Standard PPA containing negotiated prices under Schedule 202. ~~Eligibility for the Standard Fixed Price Option or the Renewable Fixed Price Option may also be affected by the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the Renewable Fixed Price Option Under the Standard PPA stated below.~~

A qualifying facility will be eligible to receive the Non-Renewable Fixed Price Option or the Renewable Fixed Price Option (as appropriate) under the Standard PPA if the nameplate capacity of the qualifying facility, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliate(s), and located at the same site, does not exceed 3 MW for solar qualifying facility projects or 10 MW for all other types of qualifying facility projects.

For purposes of determining eligibility for the Standard PPA, Non-Renewable Fixed Price Option or the Renewable Fixed Price Option, two qualifying facilities are located on the same site if the facilities or equipment providing fuel or motive force associated with the qualifying facilities are located within a five-mile radius and the qualifying facilities use the same source of energy or motive force to generate electricity.

For purposes of this section, a person is a natural person or any legal entity, and affiliate(s) are persons sharing common ownership or management, persons acting jointly or in concert with, or exercising influence over, the policies of another person or persons, or wholly owned subsidiaries. To the extent a person or affiliate is a closely held entity, a "look through" rule applies so that project equity held by limited liability companies, trusts, estates, corporations, partnerships, and other similar entities is considered to be held by the owners of the look through entity.

Two or more qualifying facilities will not be held to be owned or controlled by the same person(s) or affiliate(s) solely because they are developed by a single entity so long as they are not owned or operated by the same person(s) or affiliate(s) of the same person(s) at the time each qualifying facility seeks to enter into a power purchase agreement or at any time thereafter.

Two or more qualifying facilities that otherwise are not owned or operated by the same person(s) or affiliates(s) will not be determined to be a single qualifying facility based on the fact that they have in place a shared interest or agreement regarding interconnection facilities, interconnection-related system upgrades, or any other infrastructure not providing motive force or fuel.

SCHEDULE 201 (Continued)

The qualifying facility seeking a Standard PPA, and other facilities within the same five-mile radius, will not be considered owned or controlled by the same person(s) or affiliate(s) if the person(s) or affiliate(s) in common are passive investors whose ownership interest is primarily for obtaining value related to production tax credits, green tag values, or modified accelerated cost recovery system (MACRS) depreciation, and the qualifying facility and other facilities at issue are Family-Owned or Community-Based qualifying facilities.

B. AVOIDED COST PRICING SUMMARY

The power purchase prices are based on either the Company's Non-Renewable Avoided Costs or Renewable Avoided Costs in effect at the time the PPA is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Non-Renewable Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Non-Renewable Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Non-Renewable Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Non-Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Resource Deficiency Period, the Non-Renewable Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT avoided costs are based on the variable cost of energy plus capitalized energy costs at a 94.01% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates during the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery within the Company's service territory pursuant to a Standard PP.

SCHEDULE 201 (Continued)

AVOIDED COST PRICING SUMMARY (Continued)

Except for As-Available Energy, the Company will pay the Seller during the Fixed Price Period either the On-Peak ~~Standard~~ Non-Renewable Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for Net Output delivered in the On-Peak Period. Except for As-Available Energy, the Company will pay the Seller during the Fixed Price Period either the Off-Peak ~~Standard~~ Non-Renewable Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for Net Output delivered in the Off-Peak Period. For Net Output delivered pursuant to a Standard PPA that is delivered after the Fixed Price Period and during the term of the Standard PPA, the Company will pay the Seller Firm Electric Market Pricing. The Company will pay the Seller the As-Available Rate for all As-Available Energy delivered during the PPA term.

C. ~~Standard~~ NON-RENEWABLE FIXED PRICE OPTION

The ~~Standard~~ Non-Renewable Fixed Price Option is based on Non-Renewable ~~Standard~~ Avoided Costs including forecasted natural gas prices. It is available to all QFs that meet the eligibility requirements identified above.

~~This option is available for a maximum period of 15 years~~ Prices will be as established at the time the Final Executable ~~Standard~~ PPA is executed and will be equal to the Non-Renewable ~~Standard~~ Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Non-Renewable ~~Standard~~ Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine ~~Standard~~ Non-Renewable Avoided Costs for the ~~Standard~~ Non-Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 25.00%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 8.50%.

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
~~Standard Fixed Price Option (Continued)~~

Prices paid to the Seller under the Non-Renewable ~~Standard~~ Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Prices paid to the Seller under the Non-Renewable ~~Standard~~ Fixed Price Option for Solar QFs (Tables 3a and 3b) include a reduction for the solar integration costs in Table 7. However, if the Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 3a and 3b, for a net-zero effect.

~~Sellers with terms exceeding 15 years from the commercial operation date will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15 years after the commercial operation date selected by the Seller and memorialized in the PPA.~~

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 1a Avoided Costs Fixed Price Option for Base Load QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	70.99	73.54	153.56	252.44	204.53	82.20	97.49	135.21
2024	133.27	109.83	68.03	61.92	53.76	58.86	175.07	215.84	167.93	81.29	94.54	137.35
2025	54.43	54.34	52.97	49.95	49.80	50.78	51.57	51.80	51.61	52.09	54.47	56.86
2026	58.95	57.53	54.71	51.01	50.95	51.59	52.22	52.37	52.17	52.62	54.25	56.69
2027	58.61	57.36	54.53	51.35	51.22	51.61	52.14	52.36	52.25	52.91	55.17	57.95
2028	59.13	58.02	55.29	51.35	51.32	51.82	52.44	52.77	52.77	53.89	55.95	60.07
2029	52.30	52.41	50.89	50.01	50.11	50.21	50.29	50.40	50.51	50.84	51.67	51.78
2030	52.57	52.69	51.79	50.92	51.01	51.12	51.21	51.32	51.42	52.02	52.86	52.96
2031	53.45	53.55	53.45	52.55	52.66	52.75	52.84	52.96	53.06	54.00	55.08	55.19
2032	55.86	55.97	56.28	55.33	55.44	55.54	55.64	55.77	55.90	56.23	57.22	57.34
2033	58.06	57.20	58.92	57.58	57.51	57.79	57.86	57.86	58.02	58.41	59.17	59.02
2034	60.12	59.78	58.07	57.04	57.15	57.26	57.37	57.49	57.60	57.97	59.06	59.18
2035	59.32	59.13	58.24	57.22	57.33	57.44	57.54	57.65	57.77	58.16	59.18	59.30
2036	58.80	58.16	57.73	56.76	56.86	56.96	57.04	57.15	57.26	57.56	58.48	58.58
2037	61.14	58.40	57.52	56.56	56.66	56.76	56.85	56.95	57.05	57.28	58.25	58.35
2038	61.12	59.73	58.53	57.59	57.69	57.78	57.89	57.99	58.08	58.32	59.45	59.55
2039	61.61	61.38	60.89	60.09	60.10	60.22	60.34	60.44	60.54	61.77	63.17	63.31
2040	66.56	66.50	66.31	65.37	65.49	65.95	66.15	66.29	66.41	68.44	70.13	70.30
2041	73.28	73.40	71.35	70.33	70.49	70.66	70.83	71.01	71.13	72.27	73.96	74.15
2042	77.55	78.52	72.87	71.97	72.19	72.51	72.83	72.72	72.70	73.96	74.66	75.03
2043	78.20	77.29	74.15	73.40	73.46	73.53	73.69	73.86	74.07	74.32	76.36	76.60
2044	80.59	80.14	74.51	73.92	73.76	74.10	74.03	74.22	74.75	76.60	66.92	67.33
2045	71.03	76.76	75.98	74.90	75.45	75.49	75.35	75.62	75.75	76.35	78.34	78.73
2046	81.68	81.36	78.44	77.58	77.68	77.84	77.95	78.19	78.31	78.97	81.14	81.37
2047	85.81	84.83	82.31	81.63	81.67	81.72	81.97	82.12	82.33	83.59	86.69	86.84
2048	90.17	86.71	85.28	84.64	84.69	84.76	85.01	85.18	85.37	87.75	92.15	92.32

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 1b
Avoided Costs
Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	58.76	43.46	69.97	101.57	92.39	74.05	83.22	109.72
2024	108.81	90.46	59.88	55.80	43.57	43.57	79.25	111.36	84.34	60.90	75.17	109.83
2025	28.12	28.02	26.66	23.63	23.48	24.47	25.25	25.49	25.29	25.77	28.16	30.55
2026	32.10	30.68	27.86	24.16	24.09	24.74	25.37	25.51	25.32	25.77	27.40	29.83
2027	31.21	29.96	27.13	23.95	23.81	24.21	24.73	24.95	24.84	25.51	27.77	30.55
2028	31.16	30.06	27.33	23.39	23.36	23.85	24.47	24.80	24.81	25.93	27.99	32.11
2029	23.77	23.87	22.36	21.47	21.57	21.68	21.75	21.87	21.98	22.30	23.14	23.24
2030	23.45	23.57	22.66	21.80	21.89	22.00	22.09	22.20	22.30	22.90	23.74	23.84
2031	23.73	23.84	23.74	22.83	22.95	23.03	23.13	23.24	23.35	24.28	25.36	25.47
2032	25.73	25.83	26.14	25.20	25.31	25.40	25.51	25.64	25.76	26.09	27.09	27.20
2033	27.12	26.25	27.97	26.63	26.56	26.85	26.92	26.91	27.07	27.47	28.22	28.07
2034	28.44	28.10	26.39	25.35	25.47	25.58	25.69	25.80	25.92	26.29	27.38	27.50
2035	27.09	26.91	26.01	24.99	25.10	25.21	25.31	25.42	25.54	25.93	26.96	27.07
2036	26.02	25.38	24.94	23.98	24.08	24.18	24.26	24.36	24.48	24.78	25.70	25.80
2037	27.58	24.83	23.96	23.00	23.10	23.19	23.29	23.38	23.49	23.71	24.68	24.78
2038	26.87	25.48	24.28	23.34	23.44	23.53	23.64	23.74	23.83	24.07	25.20	25.30
2039	26.65	26.43	25.94	25.14	25.15	25.26	25.39	25.49	25.58	26.82	28.22	28.36
2040	30.89	30.83	30.64	29.70	29.83	30.29	30.48	30.62	30.74	32.77	34.47	34.63
2041	36.88	37.01	34.95	33.93	34.10	34.26	34.43	34.61	34.73	35.87	37.56	37.75
2042	40.41	41.38	35.72	34.83	35.04	35.36	35.69	35.58	35.55	36.82	37.52	37.89
2043	40.30	39.39	36.24	35.50	35.55	35.62	35.78	35.95	36.17	36.41	38.46	38.69
2044	42.04	41.58	35.95	35.36	35.20	35.55	35.47	35.66	36.19	38.04	28.37	28.77
2045	31.43	37.16	36.38	35.30	35.85	35.89	35.75	36.02	36.15	36.74	38.74	39.13
2046	41.40	41.08	38.16	37.30	37.40	37.56	37.67	37.91	38.02	38.69	40.86	41.08
2047	44.70	43.73	41.20	40.52	40.57	40.61	40.86	41.01	41.23	42.48	45.58	45.73
2048	48.35	44.89	43.47	42.83	42.87	42.95	43.19	43.36	43.55	45.93	50.34	50.50

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 2a Avoided Costs Fixed Price Option for Wind QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	70.64	73.19	153.21	252.09	204.18	81.86	97.15	134.86
2024	132.92	109.47	67.68	61.56	53.41	58.51	174.71	215.49	167.58	80.93	94.18	137.00
2025	43.23	43.13	41.77	38.74	38.60	39.58	40.37	40.60	40.40	40.88	43.27	45.66
2026	47.52	46.10	43.28	39.58	39.51	40.16	40.79	40.93	40.74	41.19	42.82	45.25
2027	46.94	45.70	42.86	39.69	39.55	39.95	40.47	40.69	40.58	41.24	43.51	46.29
2028	47.22	46.12	43.39	39.45	39.42	39.91	40.53	40.86	40.87	41.99	44.05	48.17
2029	40.15	40.26	38.74	37.86	37.96	38.06	38.14	38.25	38.37	38.69	39.53	39.63
2030	40.17	40.29	39.39	38.53	38.61	38.72	38.81	38.92	39.02	39.62	40.46	40.56
2031	40.80	40.90	40.80	39.90	40.01	40.10	40.19	40.31	40.41	41.35	42.43	42.54
2032	43.03	43.13	43.45	42.50	42.61	42.71	42.81	42.94	43.06	43.40	44.39	44.51
2033	44.89	44.02	45.74	44.40	44.34	44.62	44.69	44.68	44.84	45.24	45.99	45.85
2034	46.64	46.29	44.58	43.55	43.66	43.77	43.89	44.00	44.12	44.49	45.57	45.70
2035	45.60	45.41	44.52	43.50	43.61	43.72	43.82	43.93	44.05	44.44	45.46	45.58
2036	44.84	44.20	43.77	42.80	42.90	43.00	43.09	43.19	43.30	43.60	44.53	44.62
2037	46.85	44.11	43.24	42.28	42.37	42.47	42.56	42.66	42.77	42.99	43.96	44.06
2038	46.53	45.15	43.95	43.01	43.11	43.20	43.31	43.41	43.50	43.74	44.87	44.97
2039	46.73	46.50	46.01	45.21	45.22	45.34	45.46	45.56	45.66	46.89	48.29	48.43
2040	51.37	51.31	51.12	50.18	50.31	50.77	50.96	51.11	51.23	53.26	54.95	55.12
2041	57.78	57.91	55.85	54.84	55.00	55.16	55.34	55.51	55.63	56.78	58.46	58.65
2042	61.74	62.71	57.06	56.16	56.37	56.70	57.02	56.91	56.88	58.15	58.85	59.22
2043	62.07	61.16	58.01	57.26	57.32	57.39	57.55	57.72	57.93	58.18	60.23	60.46
2044	64.18	63.72	58.09	57.50	57.35	57.69	57.61	57.80	58.33	60.18	50.51	50.92
2045	54.17	59.91	59.12	58.05	58.59	58.63	58.49	58.76	58.89	59.49	61.48	61.87
2046	64.53	64.22	61.29	60.44	60.53	60.69	60.80	61.04	61.16	61.82	63.99	64.22
2047	68.31	67.33	64.81	64.13	64.17	64.22	64.47	64.62	64.83	66.09	69.19	69.34
2048	72.37	68.91	67.48	66.84	66.89	66.96	67.20	67.37	67.56	69.94	74.35	74.51

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 2b Avoided Costs Fixed Price Option for Wind QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	58.41	43.12	69.62	101.22	92.05	73.70	82.87	109.38
2024	108.46	90.11	59.53	55.45	43.22	43.22	78.89	111.00	83.99	60.55	74.82	109.47
2025	27.76	27.66	26.30	23.27	23.12	24.11	24.89	25.13	24.93	25.41	27.80	30.19
2026	31.74	30.31	27.49	23.79	23.73	24.37	25.00	25.15	24.95	25.40	27.03	29.47
2027	30.83	29.59	26.75	23.57	23.44	23.83	24.36	24.58	24.47	25.13	27.39	30.18
2028	30.78	29.68	26.94	23.01	22.98	23.47	24.09	24.42	24.43	25.55	27.61	31.72
2029	23.38	23.48	21.96	21.08	21.18	21.28	21.36	21.47	21.59	21.91	22.75	22.85
2030	23.05	23.17	22.27	21.40	21.49	21.60	21.69	21.80	21.90	22.50	23.34	23.44
2031	23.33	23.43	23.33	22.43	22.54	22.63	22.72	22.83	22.94	23.88	24.96	25.06
2032	25.31	25.42	25.73	24.78	24.89	24.99	25.10	25.22	25.35	25.68	26.67	26.79
2033	26.69	25.83	27.55	26.21	26.14	26.42	26.49	26.49	26.65	27.04	27.80	27.65
2034	28.01	27.67	25.95	24.92	25.03	25.15	25.26	25.37	25.49	25.86	26.95	27.07
2035	26.65	26.47	25.57	24.55	24.66	24.77	24.87	24.98	25.10	25.49	26.51	26.63
2036	25.57	24.93	24.49	23.53	23.63	23.73	23.81	23.91	24.03	24.33	25.25	25.35
2037	27.12	24.37	23.50	22.54	22.64	22.73	22.83	22.92	23.03	23.25	24.23	24.32
2038	26.40	25.02	23.82	22.87	22.97	23.07	23.17	23.27	23.36	23.60	24.73	24.83
2039	26.18	25.95	25.46	24.66	24.67	24.79	24.91	25.01	25.10	26.34	27.74	27.88
2040	30.40	30.34	30.15	29.21	29.34	29.80	29.99	30.14	30.25	32.28	33.98	34.14
2041	36.38	36.51	34.45	33.44	33.60	33.76	33.93	34.11	34.23	35.37	37.06	37.25
2042	39.90	40.87	35.22	34.32	34.53	34.86	35.18	35.07	35.04	36.31	37.01	37.38
2043	39.78	38.87	35.73	34.98	35.04	35.10	35.26	35.43	35.65	35.89	37.94	38.17
2044	41.51	41.05	35.42	34.83	34.68	35.02	34.94	35.13	35.66	37.51	27.84	28.25
2045	30.89	36.62	35.84	34.76	35.31	35.35	35.21	35.48	35.61	36.20	38.20	38.59
2046	40.85	40.53	37.61	36.75	36.85	37.01	37.11	37.36	37.47	38.14	40.30	40.53
2047	44.14	43.16	40.64	39.96	40.00	40.05	40.30	40.45	40.66	41.92	45.02	45.17
2048	47.78	44.32	42.89	42.25	42.30	42.37	42.62	42.79	42.98	45.36	49.76	49.92

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 3a Avoided Costs Fixed Price Option for Solar QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	69.55	72.10	152.12	251.00	203.08	80.76	96.05	133.77
2024	131.80	108.36	66.56	60.45	52.29	57.39	173.60	214.37	166.46	79.82	93.07	135.88
2025	32.32	32.23	30.86	27.84	27.69	28.67	29.46	29.69	29.50	29.98	32.36	34.75
2026	36.39	34.97	32.14	28.45	28.38	29.03	29.66	29.80	29.61	30.06	31.69	34.12
2027	35.58	34.34	31.50	28.33	28.19	28.59	29.11	29.33	29.22	29.88	32.15	34.93
2028	35.63	34.53	31.79	27.86	27.83	28.32	28.94	29.27	29.28	30.39	32.46	36.57
2029	28.32	28.43	26.91	26.03	26.13	26.23	26.31	26.42	26.54	26.86	27.70	27.80
2030	28.10	28.22	27.32	26.45	26.54	26.65	26.74	26.85	26.95	27.55	28.39	28.49
2031	28.48	28.58	28.48	27.58	27.69	27.78	27.87	27.99	28.09	29.03	30.11	30.22
2032	30.53	30.63	30.95	30.00	30.11	30.21	30.31	30.44	30.56	30.90	31.89	32.01
2033	32.06	31.19	32.91	31.57	31.51	31.79	31.86	31.86	32.01	32.41	33.17	33.02
2034	33.51	33.16	31.45	30.42	30.53	30.65	30.76	30.87	30.99	31.36	32.45	32.57
2035	32.24	32.05	31.16	30.14	30.25	30.36	30.46	30.57	30.69	31.08	32.10	32.22
2036	31.25	30.61	30.17	29.21	29.31	29.41	29.49	29.60	29.71	30.01	30.93	31.03
2037	32.94	30.19	29.32	28.36	28.46	28.55	28.65	28.75	28.85	29.07	30.05	30.15
2038	32.34	30.96	29.76	28.81	28.91	29.01	29.11	29.21	29.30	29.54	30.67	30.77
2039	32.24	32.01	31.52	30.72	30.73	30.85	30.97	31.07	31.17	32.40	33.80	33.94
2040	36.58	36.53	36.34	35.40	35.52	35.98	36.18	36.32	36.44	38.47	40.16	40.33
2041	42.69	42.82	40.76	39.75	39.91	40.07	40.25	40.42	40.54	41.69	43.37	43.56
2042	46.34	47.31	41.66	40.76	40.98	41.30	41.62	41.51	41.49	42.75	43.45	43.82
2043	46.35	45.44	42.30	41.55	41.61	41.68	41.84	42.01	42.22	42.47	44.51	44.75
2044	48.19	47.73	42.10	41.51	41.36	41.70	41.62	41.81	42.34	44.19	34.52	34.93
2045	37.76	43.50	42.71	41.64	42.18	42.22	42.08	42.35	42.48	43.08	45.07	45.46
2046	47.83	47.52	44.59	43.74	43.83	44.00	44.10	44.34	44.46	45.12	47.29	47.52
2047	51.27	50.29	47.77	47.09	47.13	47.18	47.43	47.58	47.79	49.05	52.15	52.29
2048	55.03	51.57	50.14	49.50	49.55	49.62	49.86	50.03	50.22	52.60	57.01	57.17

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
NON-RENEWABLE ~~STANDARD~~ FIXED PRICE OPTION (Continued)

TABLE 3b												
Avoided Costs												
Fixed Price Option for Solar QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	57.32	42.02	68.53	100.13	90.95	72.61	81.78	108.28
2024	107.34	88.99	58.41	54.33	42.10	42.10	77.78	109.89	82.87	59.43	73.70	108.36
2025	26.62	26.52	25.16	22.13	21.98	22.97	23.75	23.99	23.79	24.27	26.66	29.05
2026	30.57	29.15	26.32	22.63	22.56	23.21	23.84	23.98	23.79	24.24	25.87	28.30
2027	29.64	28.40	25.57	22.39	22.25	22.65	23.17	23.39	23.28	23.94	26.21	28.99
2028	29.57	28.47	25.73	21.80	21.76	22.26	22.88	23.21	23.21	24.33	26.40	30.51
2029	22.14	22.24	20.73	19.84	19.94	20.05	20.13	20.24	20.35	20.68	21.51	21.61
2030	21.79	21.91	21.00	20.14	20.23	20.34	20.43	20.54	20.64	21.24	22.08	22.18
2031	22.04	22.14	22.04	21.14	21.25	21.34	21.43	21.55	21.65	22.59	23.67	23.78
2032	24.00	24.10	24.42	23.47	23.58	23.67	23.78	23.91	24.03	24.37	25.36	25.48
2033	25.35	24.49	26.21	24.87	24.80	25.08	25.15	25.15	25.31	25.70	26.46	26.31
2034	26.64	26.30	24.59	23.55	23.67	23.78	23.89	24.00	24.12	24.49	25.58	25.70
2035	25.26	25.07	24.18	23.15	23.26	23.37	23.48	23.59	23.71	24.10	25.12	25.23
2036	24.14	23.50	23.07	22.10	22.20	22.30	22.38	22.49	22.60	22.90	23.82	23.92
2037	25.66	22.92	22.05	21.09	21.18	21.28	21.38	21.47	21.58	21.80	22.77	22.87
2038	24.91	23.53	22.33	21.39	21.49	21.58	21.69	21.79	21.88	22.12	23.25	23.35
2039	24.66	24.44	23.95	23.14	23.16	23.27	23.40	23.50	23.59	24.83	26.22	26.37
2040	28.85	28.79	28.61	27.66	27.79	28.25	28.45	28.59	28.71	30.74	32.43	32.60
2041	34.80	34.93	32.87	31.86	32.02	32.18	32.36	32.53	32.65	33.80	35.48	35.68
2042	38.29	39.26	33.61	32.71	32.92	33.25	33.57	33.46	33.43	34.70	35.40	35.77
2043	38.14	37.23	34.08	33.33	33.39	33.46	33.62	33.79	34.00	34.25	36.30	36.53
2044	39.83	39.37	33.74	33.15	33.00	33.34	33.27	33.45	33.99	35.83	26.16	26.57
2045	29.18	34.91	34.13	33.05	33.59	33.64	33.50	33.77	33.90	34.49	36.49	36.88
2046	39.10	38.79	35.86	35.01	35.10	35.26	35.37	35.61	35.73	36.39	38.56	38.79
2047	42.36	41.38	38.86	38.18	38.22	38.27	38.52	38.67	38.88	40.14	43.24	43.38
2048	45.96	42.50	41.07	40.43	40.48	40.56	40.80	40.97	41.16	43.54	47.94	48.11

SCHEDULE 201 (Continued)

~~STANDARD POWER PURCHASE AGREEMENT AND PRICES (Continued)~~

D. RENEWABLE FIXED PRICE OPTION

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210 and that satisfy the eligibility requirements identified above.

~~This option is available for a maximum term of 15 years.~~ Prices will be as established at the time the Final Executable ~~Standard~~ PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Seller will retain and transfer Environmental Attributes consistent with the terms and conditions of the Standard PPA. ~~Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.~~

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 25.00%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 8.50%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Prices paid to the Seller under the Renewable Fixed Price Option for Solar QFs (Tables 6a and 6b) include a reduction for the s~~S~~olar integration costs in Table 7. However, if the Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 6a and 6b.

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~

RENEWABLE FIXED PRICE OPTION (Continued)

~~Sellers with terms exceeding 15 years from the commercial operation date will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15 years following the commercial operation date selected by the Seller and memorialized in the PPA.~~

TABLE 4a Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF On-Peak Forecast ($/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	70.99	73.54	153.56	252.44	204.53	82.20	97.49	135.21
2024	133.27	109.83	68.03	61.92	53.76	58.86	175.07	215.84	167.93	81.29	94.54	137.35
2025	70.54	62.76	48.89	46.86	44.15	45.85	84.41	97.94	82.04	53.29	57.69	71.90
2026	71.99	64.05	49.89	47.82	45.06	46.79	86.14	99.95	83.72	54.38	58.87	73.37
2027	73.46	65.36	50.91	48.80	45.98	47.74	87.91	102.00	85.44	55.49	60.07	74.87
2028	74.84	66.59	51.89	49.74	46.87	48.67	89.54	103.88	87.03	56.55	61.21	76.27
2029	76.50	68.06	53.02	50.82	47.89	49.72	91.54	106.22	88.98	57.79	62.56	77.97
2030	78.07	69.46	54.11	51.86	48.87	50.74	93.42	108.40	90.80	58.98	63.84	79.57
2031	79.67	70.88	55.22	52.92	49.87	51.78	95.33	110.62	92.66	60.18	65.15	81.20
2032	80.97	72.03	56.08	53.75	50.64	52.59	96.91	112.46	94.19	61.14	66.19	82.53
2033	82.97	73.82	57.50	55.12	51.93	53.92	99.28	115.20	96.50	62.68	67.85	84.56
2034	84.77	75.43	58.78	56.35	53.10	55.13	101.42	117.66	98.57	64.06	69.34	86.39
2035	86.40	76.87	59.88	57.40	54.08	56.15	103.39	119.96	100.49	65.27	70.66	88.06
2036	87.92	78.22	60.93	58.40	55.02	57.13	105.20	122.07	102.25	66.41	71.89	89.60
2037	89.98	80.05	62.36	59.77	56.32	58.48	107.67	124.93	104.65	67.97	73.58	91.70
2038	91.82	81.69	63.64	61.00	57.47	59.68	109.88	127.49	106.79	69.36	75.09	93.58
2039	93.70	83.37	64.94	62.25	58.65	60.90	112.13	130.10	108.98	70.78	76.63	95.50
2040	95.46	84.94	66.19	63.45	59.79	62.07	114.21	132.50	111.01	72.13	78.08	97.29
2041	97.58	86.82	67.63	64.82	61.08	63.42	116.77	135.49	113.49	73.71	79.80	99.45
2042	99.58	88.60	69.02	66.15	62.33	64.72	119.16	138.26	115.82	75.22	81.43	101.49
2043	101.62	90.41	70.43	67.51	63.61	66.04	121.60	141.09	118.19	76.77	83.10	103.57
2044	103.40	91.99	71.66	68.68	64.72	67.20	123.74	143.57	120.26	78.11	84.55	105.38
2045	105.95	94.28	73.47	70.43	66.37	68.90	126.76	147.06	123.21	80.07	86.67	107.98
2046	107.99	96.08	74.85	71.74	67.60	70.19	129.23	149.94	125.60	81.58	88.31	110.07
2047	110.21	98.05	76.38	73.21	68.98	71.63	131.88	153.02	128.18	83.25	90.12	112.32
2048	112.14	99.77	77.71	74.49	70.18	72.87	134.19	155.71	130.43	84.71	91.70	114.29

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~

RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 4b												
Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF												
Off-Peak Forecast ($/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0.00	0.00	0.00	0.00	58.76	43.46	69.97	101.57	92.39	74.05	83.22	109.72
2024	108.81	90.46	59.88	55.80	43.57	43.57	79.25	111.36	84.34	60.90	75.17	109.83
2025	36.11	30.02	19.87	18.52	14.46	14.46	26.30	36.96	27.99	20.21	24.95	36.45
2026	36.85	30.64	20.28	18.90	14.76	14.76	26.84	37.71	28.56	20.62	25.46	37.19
2027	37.60	31.26	20.69	19.29	15.06	15.06	27.39	38.49	29.15	21.05	25.98	37.96
2028	38.27	31.82	21.06	19.63	15.32	15.32	27.87	39.17	29.67	21.42	26.44	38.63
2029	39.16	32.56	21.55	20.08	15.68	15.68	28.52	40.08	30.36	21.92	27.05	39.53
2030	39.96	33.22	21.99	20.49	16.00	16.00	29.11	40.90	30.98	22.37	27.61	40.34
2031	40.78	33.91	22.44	20.91	16.33	16.33	29.70	41.74	31.61	22.83	28.17	41.16
2032	41.50	34.51	22.84	21.28	16.62	16.62	30.23	42.48	32.17	23.23	28.67	41.89
2033	42.47	35.31	23.37	21.78	17.01	17.01	30.93	43.47	32.92	23.77	29.34	42.87
2034	43.34	36.03	23.85	22.23	17.35	17.35	31.57	44.36	33.60	24.26	29.94	43.75
2035	44.23	36.77	24.34	22.68	17.71	17.71	32.21	45.26	34.28	24.75	30.55	44.64
2036	45.01	37.42	24.77	23.08	18.02	18.02	32.78	46.07	34.89	25.19	31.10	45.43
2037	46.06	38.29	25.35	23.62	18.44	18.44	33.55	47.14	35.70	25.78	31.82	46.49
2038	47.00	39.08	25.87	24.10	18.82	18.82	34.23	48.10	36.43	26.31	32.47	47.44
2039	47.97	39.88	26.40	24.60	19.21	19.21	34.93	49.09	37.18	26.85	33.14	48.41
2040	48.81	40.58	26.86	25.03	19.55	19.55	35.55	49.96	37.84	27.32	33.72	49.27
2041	49.95	41.53	27.49	25.62	20.00	20.00	36.38	51.12	38.72	27.96	34.51	50.42
2042	50.97	42.38	28.05	26.14	20.41	20.41	37.13	52.17	39.51	28.53	35.22	51.45
2043	52.02	43.25	28.63	26.68	20.83	20.83	37.89	53.24	40.32	29.11	35.94	52.51
2044	52.94	44.01	29.13	27.15	21.20	21.20	38.56	54.18	41.04	29.63	36.57	53.44
2045	54.17	45.04	29.81	27.78	21.69	21.69	39.45	55.44	41.99	30.32	37.42	54.68
2046	55.28	45.96	30.42	28.35	22.14	22.14	40.26	56.58	42.85	30.94	38.19	55.80
2047	56.41	46.90	31.05	28.93	22.59	22.59	41.09	57.74	43.73	31.57	38.97	56.94
2048	57.41	47.73	31.59	29.44	22.99	22.99	41.81	58.76	44.50	32.13	39.66	57.95

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 5a												
Renewable Avoided Costs												
Renewable Fixed Price Option for Wind QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	70.64	73.19	153.21	252.09	204.18	81.86	97.15	134.86
2024	132.92	109.47	67.68	61.56	53.41	58.51	174.71	215.49	167.58	80.93	94.18	137.00
2025	59.34	51.56	37.69	35.66	32.95	34.64	73.21	86.74	70.84	42.09	46.48	60.69
2026	60.56	52.62	38.46	36.39	33.63	35.35	74.71	88.52	72.29	42.95	47.44	61.94
2027	61.80	53.69	39.25	37.14	34.32	36.08	76.24	90.33	73.77	43.83	48.41	63.21
2028	62.93	54.69	39.99	37.84	34.97	36.76	77.63	91.98	75.12	44.65	49.31	64.37
2029	64.35	55.92	40.87	38.67	35.74	37.57	79.40	94.07	76.83	45.64	50.41	65.82
2030	65.67	57.06	41.71	39.46	36.47	38.34	81.02	96.00	78.40	46.58	51.45	67.17
2031	67.02	58.23	42.57	40.27	37.22	39.13	82.68	97.97	80.01	47.53	52.50	68.55
2032	68.14	59.20	43.25	40.92	37.81	39.75	84.08	99.63	81.36	48.31	53.36	69.69
2033	69.79	60.64	44.33	41.94	38.76	40.75	86.11	102.02	83.32	49.50	54.67	71.38
2034	71.28	61.94	45.30	42.86	39.61	41.64	87.93	104.17	85.09	50.57	55.85	72.91
2035	72.68	63.15	46.16	43.68	40.36	42.43	89.67	106.24	86.77	51.55	56.94	74.34
2036	73.96	64.26	46.97	44.44	41.07	43.17	91.25	108.11	88.29	52.45	57.93	75.64
2037	75.69	65.77	48.07	45.48	42.03	44.19	93.38	110.64	90.36	53.68	59.29	77.42
2038	77.24	67.11	49.06	46.42	42.89	45.10	95.29	112.91	92.21	54.78	60.51	79.00
2039	78.82	68.49	50.06	47.37	43.77	46.02	97.25	115.22	94.10	55.91	61.75	80.62
2040	80.27	69.76	51.01	48.26	44.60	46.89	99.02	117.32	95.82	56.95	62.90	82.10
2041	82.09	71.32	52.14	49.33	45.58	47.92	101.27	119.99	98.00	58.22	64.30	83.96
2042	83.77	72.78	53.20	50.34	46.52	48.91	103.35	122.45	100.00	59.41	65.62	85.68
2043	85.48	74.27	54.29	51.37	47.47	49.91	105.46	124.96	102.05	60.63	66.96	87.43
2044	86.98	75.58	55.24	52.27	48.30	50.78	107.32	127.16	103.85	61.69	68.14	88.97
2045	89.10	77.42	56.62	53.57	49.51	52.05	109.90	130.20	106.35	63.21	69.81	91.13
2046	90.85	78.93	57.70	54.59	50.45	53.04	112.08	132.80	108.45	64.43	71.16	92.92
2047	92.71	80.55	58.88	55.71	51.48	54.12	114.38	135.52	110.68	65.75	72.62	94.82
2048	94.33	81.96	59.91	56.68	52.38	55.07	116.39	137.90	112.62	66.90	73.90	96.49

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 5b												
Renewable Avoided Costs												
Renewable Fixed Price Option for Wind QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	58.41	43.12	69.62	101.22	92.05	73.70	82.87	109.38
2024	108.46	90.11	59.53	55.45	43.22	43.22	78.89	111.00	83.99	60.55	74.82	109.47
2025	35.75	29.66	19.51	18.16	14.10	14.10	25.94	36.60	27.63	19.85	24.59	36.09
2026	36.48	30.27	19.91	18.53	14.39	14.39	26.47	37.35	28.20	20.26	25.09	36.83
2027	37.23	30.89	20.32	18.91	14.68	14.68	27.01	38.11	28.77	20.67	25.60	37.58
2028	37.89	31.43	20.68	19.24	14.94	14.94	27.49	38.78	29.28	21.04	26.06	38.25
2029	38.77	32.17	21.16	19.69	15.29	15.29	28.13	39.69	29.97	21.53	26.66	39.14
2030	39.57	32.83	21.59	20.10	15.60	15.60	28.71	40.50	30.58	21.97	27.21	39.94
2031	40.38	33.50	22.04	20.51	15.92	15.92	29.30	41.33	31.21	22.42	27.77	40.76
2032	41.09	34.09	22.43	20.87	16.20	16.20	29.81	42.06	31.76	22.81	28.26	41.48
2033	42.05	34.89	22.95	21.36	16.58	16.58	30.51	43.04	32.50	23.35	28.92	42.44
2034	42.91	35.60	23.42	21.79	16.92	16.92	31.13	43.92	33.16	23.82	29.51	43.31
2035	43.79	36.33	23.90	22.24	17.27	17.27	31.77	44.82	33.84	24.31	30.11	44.20
2036	44.56	36.97	24.32	22.63	17.57	17.57	32.33	45.62	34.44	24.74	30.65	44.98
2037	45.60	37.83	24.89	23.16	17.98	17.98	33.09	46.68	35.24	25.32	31.36	46.03
2038	46.53	38.61	25.40	23.64	18.35	18.35	33.76	47.63	35.97	25.84	32.00	46.97
2039	47.49	39.40	25.92	24.12	18.73	18.73	34.46	48.61	36.70	26.37	32.66	47.94
2040	48.33	40.09	26.38	24.55	19.06	19.06	35.06	49.47	37.35	26.83	33.23	48.78
2041	49.45	41.03	26.99	25.12	19.50	19.50	35.88	50.62	38.22	27.46	34.01	49.92
2042	50.47	41.87	27.54	25.63	19.90	19.90	36.62	51.66	39.00	28.02	34.71	50.94
2043	51.50	42.73	28.11	26.16	20.31	20.31	37.37	52.72	39.80	28.60	35.42	51.99
2044	52.41	43.48	28.60	26.62	20.67	20.67	38.03	53.65	40.51	29.10	36.04	52.91
2045	53.63	44.50	29.27	27.24	21.15	21.15	38.91	54.90	41.45	29.78	36.88	54.14
2046	54.73	45.41	29.87	27.80	21.58	21.58	39.71	56.03	42.30	30.39	37.64	55.25
2047	55.85	46.34	30.48	28.37	22.03	22.03	40.52	57.17	43.17	31.01	38.41	56.38
2048	56.84	47.16	31.02	28.87	22.42	22.42	41.24	58.18	43.93	31.56	39.09	57.38

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 6a Renewable Avoided Costs Renewable Fixed Price Option for Solar QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	69.55	72.10	152.12	251.00	203.08	80.76	96.05	133.77
2024	131.80	108.36	66.56	60.45	52.29	57.39	173.60	214.37	166.46	79.82	93.07	135.88
2025	48.43	40.65	26.78	24.75	22.05	23.74	62.30	75.83	59.93	31.18	35.58	49.79
2026	49.42	41.48	27.33	25.26	22.50	24.22	63.58	77.39	61.16	31.82	36.31	50.81
2027	50.44	42.33	27.89	25.78	22.96	24.72	64.88	78.97	62.42	32.47	37.05	51.85
2028	51.34	43.10	28.40	26.24	23.38	25.17	66.04	80.38	63.53	33.06	37.72	52.78
2029	52.52	44.09	29.04	26.84	23.91	25.74	67.57	82.24	65.00	33.81	38.58	53.99
2030	53.60	44.99	29.64	27.39	24.40	26.27	68.95	83.93	66.33	34.51	39.37	55.10
2031	54.70	45.91	30.25	27.95	24.90	26.81	70.36	85.65	67.69	35.21	40.18	56.23
2032	55.64	46.70	30.75	28.42	25.31	27.25	71.58	87.13	68.86	35.81	40.86	57.19
2033	56.96	47.81	31.50	29.11	25.93	27.92	73.28	89.19	70.49	36.67	41.84	58.55
2034	58.15	48.81	32.17	29.73	26.48	28.51	74.80	91.04	71.96	37.44	42.72	59.78
2035	59.32	49.79	32.80	30.32	27.00	29.07	76.31	92.88	73.41	38.19	43.58	60.98
2036	60.36	50.66	33.37	30.84	27.47	29.58	77.65	94.52	74.70	38.86	44.34	62.05
2037	61.78	51.85	34.16	31.57	28.12	30.28	79.47	96.73	76.45	39.77	45.38	63.50
2038	63.04	52.91	34.86	32.22	28.70	30.90	81.10	98.71	78.01	40.58	46.31	64.80
2039	64.33	54.00	35.57	32.88	29.28	31.53	82.76	100.73	79.61	41.42	47.26	66.13
2040	65.49	54.97	36.22	33.48	29.82	32.10	84.24	102.53	81.04	42.16	48.11	67.32
2041	67.00	56.23	37.05	34.24	30.50	32.83	86.18	104.90	82.91	43.13	49.21	68.87
2042	68.37	57.39	37.81	34.94	31.12	33.51	87.95	107.05	84.61	44.01	50.22	70.28
2043	69.77	58.56	38.58	35.66	31.76	34.19	89.75	109.24	86.34	44.92	51.25	71.72
2044	70.99	59.59	39.25	36.28	32.31	34.79	91.33	111.17	87.86	45.70	52.15	72.98
2045	72.68	61.01	40.20	37.16	33.10	35.64	93.49	113.79	89.94	46.80	53.40	74.71
2046	74.15	62.23	41.00	37.89	33.75	36.34	95.38	116.10	91.75	47.73	54.47	76.22
2047	75.66	63.51	41.84	38.67	34.44	37.08	97.33	118.47	93.63	48.71	55.58	77.78
2048	76.99	64.62	42.57	39.34	35.04	37.73	99.05	120.56	95.28	49.56	56.55	79.14

SCHEDULE 201 (Continued)

~~PRICING OPTIONS FOR STANDARD PPA (Continued)~~
RENEWABLE FIXED PRICE OPTION (Continued)

TABLE 6b Renewable Avoided Costs Renewable Fixed Price Option for Solar QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2023	0.00	0.00	0.00	0.00	57.32	42.02	68.53	100.13	90.95	72.61	81.78	108.28
2024	107.34	88.99	58.41	54.33	42.10	42.10	77.78	109.89	82.87	59.43	73.70	108.36
2025	34.61	28.52	18.37	17.02	12.96	12.96	24.80	35.46	26.49	18.71	23.45	34.95
2026	35.32	29.10	18.75	17.37	13.22	13.22	25.31	36.18	27.03	19.09	23.93	35.66
2027	36.04	29.70	19.13	17.72	13.50	13.50	25.83	36.92	27.59	19.48	24.42	36.39
2028	36.68	30.22	19.47	18.03	13.73	13.73	26.28	37.57	28.07	19.83	24.84	37.03
2029	37.53	30.93	19.92	18.46	14.05	14.05	26.89	38.45	28.73	20.29	25.43	37.90
2030	38.30	31.56	20.33	18.83	14.34	14.34	27.45	39.24	29.32	20.71	25.95	38.68
2031	39.09	32.21	20.75	19.22	14.64	14.64	28.01	40.04	29.92	21.13	26.48	39.47
2032	39.78	32.78	21.11	19.56	14.89	14.89	28.50	40.75	30.44	21.50	26.94	40.16
2033	40.71	33.54	21.61	20.02	15.24	15.24	29.17	41.70	31.16	22.01	27.58	41.10
2034	41.54	34.23	22.05	20.43	15.55	15.55	29.77	42.56	31.80	22.46	28.14	41.95
2035	42.39	34.93	22.50	20.84	15.87	15.87	30.37	43.43	32.45	22.92	28.72	42.81
2036	43.14	35.55	22.90	21.21	16.15	16.15	30.91	44.19	33.02	23.32	29.22	43.56
2037	44.15	36.38	23.43	21.71	16.53	16.53	31.63	45.22	33.79	23.87	29.91	44.58
2038	45.05	37.12	23.91	22.15	16.87	16.87	32.28	46.15	34.48	24.35	30.52	45.49
2039	45.97	37.88	24.40	22.61	17.21	17.21	32.94	47.10	35.19	24.85	31.14	46.42
2040	46.78	38.55	24.83	23.00	17.51	17.51	33.52	47.92	35.81	25.29	31.69	47.24
2041	47.88	39.45	25.41	23.54	17.93	17.93	34.31	49.05	36.64	25.88	32.43	48.34
2042	48.86	40.26	25.93	24.02	18.29	18.29	35.01	50.05	37.40	26.41	33.10	49.33
2043	49.86	41.09	26.47	24.52	18.67	18.67	35.73	51.08	38.16	26.95	33.78	50.35
2044	50.73	41.81	26.93	24.94	18.99	18.99	36.35	51.97	38.83	27.42	34.37	51.23
2045	51.92	42.79	27.56	25.53	19.44	19.44	37.20	53.19	39.74	28.07	35.17	52.43
2046	52.99	43.66	28.13	26.05	19.84	19.84	37.97	54.28	40.56	28.64	35.89	53.50
2047	54.07	44.56	28.70	26.59	20.25	20.25	38.74	55.39	41.39	29.23	36.63	54.60
2048	55.02	45.34	29.20	27.05	20.60	20.60	39.42	56.37	42.11	29.74	37.27	55.56

SCHEDULE 201 (Continued)

WIND INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2023	0.35	1.44
2024	0.35	1.47
2025	0.36	1.50
2026	0.37	1.53
2027	0.37	1.56
2028	0.38	1.59
2029	0.39	1.63
2030	0.40	1.66
2031	0.41	1.69
2032	0.41	1.73
2033	0.42	1.76
2034	0.43	1.80
2035	0.44	1.84
2036	0.45	1.87
2037	0.46	1.91
2038	0.47	1.95
2039	0.48	1.99
2040	0.49	2.03
2041	0.50	2.07
2042	0.51	2.12
2043	0.52	2.16
2044	0.53	2.21
2045	0.54	2.25
2046	0.55	2.30
2047	0.56	2.34
2048	0.57	2.39

E. AS-AVAILABLE RATE

The As-Available Rate is based on the Avoided Energy Cost for surplus energy at the time of delivery. The As-Available Rate is equal to the Avoided Energy Cost. The Company will purchase As-Available Energy at the As-Available Rate. QFs seeking an As-Available Rate should request that PGE prepare a draft power purchase agreement that permits the QF to provide Net Output on an as-available basis.

SCHEDULE 201 (Continued)

~~**Avoided Energy Cost:**~~

The Avoided Energy Cost means eighty-two and four tenths percent (82.4%) of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices. Each day's index prices will reflect the relative proportions of peak hours and off-peak hours in the month as follows:

$$.824 * \left(\sum_{X=1}^{n} \{(\text{ICE Mid-C Physical Peak (bilateral) Avg}_X * \text{applicable peak index hours for day}) + (\text{ICE Mid-C Physical Off-Peak (bilateral) Avg}_X * \text{applicable off-peak index hours for day})\} / (n*24)\right)$$

where n = number of days in the month

~~**Mid-C Index Price**~~

As used in this schedule, the daily Mid-C Index Price shall be the applicable day-ahead Intercontinental Exchange ("ICE") Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) indices representative of the OTC market for WSPP Schedule-C physical Firm Energy transactions at the Mid-C trading hub. Product details for the Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) are found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

V. MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail customer account will be charged $10.00 per month.

~~**INSURANCE REQUIREMENTS**~~

~~The following insurance requirements are applicable to Sellers with a Standard PPA:~~

~~1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.~~

~~2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such~~

~~liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.~~

~~3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.~~

~~**TRANSMISSION AGREEMENTS**~~

~~If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.~~

VI. INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a G~~g~~eneration Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Concluded)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's ~~distribution s~~System must comply with all requirements for interconnection as established pursuant to Commission rule or order, in the Company's Rules and Regulations (Rule C), or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

~~**DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD FIXED PRICE OPTION OR THE RENEWABLE FIXED PRICE OPTION UNDER THE STANDARD PPA**~~

~~A QF will be eligible to receive the Standard Fixed Price Option or the Renewable Fixed Price Option (as appropriate) under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 3 MW for solar QF projects or 10 MW for all other types of QF projects. Solar QF projects with nameplate capacity (as calculated in this paragraph) that exceed 3 MW but do not exceed 10 MW are eligible for a Standard PPA containing negotiated prices under Schedule 202. A Community-Based or Family-Owned QF is exempt from these restrictions.~~

~~**Definition of Community-Based**~~

~~A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.~~

~~After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.~~

~~**Definition of Family-Owned**~~

~~After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered~~

~~held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.~~

~~Definition of Person(s) or Affiliated Person(s)~~

~~As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.~~

~~Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.~~

~~Definition of Same Site~~

~~For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for standard pricing or negotiated pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for standard pricing or negotiated pricing under the Standard PPA is sought.~~

~~Definition of Shared Interconnection and Infrastructure~~

~~QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to standard pricing or negotiated pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for standard pricing or negotiated pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.~~

~~OTHER DEFINITIONS~~

~~As-Available Energy~~

~~As-Available Energy means 1) all Net Output delivered to PGE if Seller elected the As-~~

~~Available Rate option within a Standard PPA~~, ~~or 2) (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year as defined under the Standard PPA year; and (c) for deliveries above the nameplate capacity in any hour.~~

~~Deliveries pursuant to an Off-System PPA that are above the nameplate capacity in any hour solely for the purpose of accommodating hourly scheduling in whole megawatts by a third-party transmission provider will not be subject to the As-Available Rate.~~

~~Mid-C Index Price~~
~~As used in this schedule, the daily Mid-C Index Price shall be the applicable day-ahead Intercontinental Exchange ("ICE") Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) indices representative of the OTC market for WSPP Schedule C physical Firm Energy transactions at the Mid-C trading hub. Product details for the Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) are found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.~~

~~Avoided Energy Cost:~~

~~The Avoided Energy Cost means eighty-two and four tenths percent (82.4%) of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices. Each day's index prices will reflect the relative proportions of peak hours and off-peak hours in the month as follows:~~

$$.824 * \left(\sum_{X=1}^{n} \{(\text{ICE Mid-C Physical Peak (bilateral) Avg}_X * \text{applicable peak index hours for day}) + (\text{ICE Mid-C Physical Off-Peak (bilateral) Avg}_X * \text{applicable off-peak index hours for day})\} / (n*24)\right)$$

where n = number of days in the month

~~OTHER DEFINITIONS (Continued)~~

~~Definition of RPS Attributes~~

~~As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.~~

~~Definition of Environmental Attributes~~

~~As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx),~~

~~nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.~~

~~Definition of Resource Sufficiency Period~~

~~This is the period from the current year through 2024.~~

~~Definition of Resource Deficiency Period~~

~~This is the period from 2025.~~

~~Definition of Renewable Resource Sufficiency Period~~

~~This is the period from the current year through 2024.~~

~~Definition of Renewable Resource Deficiency Period~~

~~This is the period from 2025.~~

VII. DISPUTE RESOLUTION

Upon request, the qualifying facility~~QF~~ will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the qualifying facility~~QF~~ in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the qualifying facility~~QF~~ meets the above-described criteria for entitlement to ~~standard pricing or negotiated pricing under~~ the Standard PPA.

~~DISPUTE RESOLUTION (Continued)~~

The QF may present disputes to the Commission for resolution using the ~~following~~ process outlined in the applicable statutes and Commission rules.~~:~~

However, ~~T~~the ~~QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The~~ QF may not file such a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract ~~a complaint~~ during any 15-day or 10-day period in which the utility has the obligation to respond, but must wait until the 15-day or 10-day period has passed.

~~The utility may respond to the complaint within ten days of service.~~

~~The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.~~

~~SPECIAL CONDITIONS~~

~~1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.~~

2. ~~If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.~~

3. ~~Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.~~

~~TERM OF AGREEMENT~~

~~Not less than one year and not to exceed 20 years from the commercial operation date selected by the Seller and memorialized in the PPA.~~

Idaho Power's

Revised Schedule 85

CLEAN

SCHEDULE 85
COGENERATION AND SMALL POWER PRODUCTION STANDARD CONTRACT RATES

AVAILABILITY

Service under this schedule is available for power delivered to the Company's control area within the State of Oregon by a Qualifying Facility (QF). (C)

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1. Owns or operates a Qualifying Facility meeting the Eligibility Threshold defined below and desires to sell Net Output generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract; (C)

2. Meets all applicable requirements of the Company's Generation Interconnection Process.

For Qualifying Facilities with a Nameplate Capacity Rating greater than 10 MW, a negotiated Non-Standard Contract between the Seller and the Company is required. (C)

DEFINITIONS

Eligibility Threshold is the Nameplate Capacity Rating requirement of a Qualifying Facility in order to be eligible for the terms and conditions of the Standard Contract. The separate Eligibility Threshold delineations are: (C)

1. For all solar QF projects:
    a. With a Nameplate Capacity Rating no greater than 3 MW – the project is eligible for a Standard Contract with fixed terms and standard avoided cost prices; (C)
    b. With a Nameplate Capacity Rating above 3 MW and less than or equal to 10 MW – the project is eligible for a Standard Contract with fixed terms and negotiated avoided cost prices; (C)
2. For all non-solar QF projects with a Nameplate Capacity Rating of 10 MW or less – the project is eligible for a Standard Contract with fixed terms and standard avoided cost prices. (C)

Energy means the electric energy, expressed in kWh. (D)

Energy Sales Agreement means the power purchase agreement between the Company and the Seller. (N)

FERC means the Federal Energy Regulatory Commission. (N)

Firm Energy means a specified quantity of energy committed by a QF to the Company. (N)

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards. The Generation Interconnection Process is managed by the Company's Load Serving Operations. (C)

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1,000.

Intermittent describes a Qualifying Facility that produces electrical energy from the use of wind, solar or run of river hydro as the prime mover.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

Nameplate Capacity Rating means maximum installed instantaneous power production capacity of the completed QF, expressed in MW (AC), and measured at the Point of Interconnection when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant. (C)
(C)

Net Output means all energy and capacity produced by the Qualifying Facility, less Station Service, Losses, and other adjustments, flowing through the Point of Interconnection. (C)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a Nameplate Capacity Rating which does not meet the Eligibility Threshold and desires to sell Energy generated by the Qualifying Facility to the Company. The starting point for negotiation of price is the avoided cost components established in this schedule and may be modified to address specific factors mandated by federal and state law, including (C)
(C)

1. The utility's system cost data;

2. The availability of capacity or energy from a Qualifying Facility during the system daily and seasonal peak periods, including: (C)
(C)

   a. The ability of the utility to dispatch the Qualifying Facility;

   b. The expected or demonstrated reliability of the Qualifying Facility;

   c. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for non-compliance;

   d. The extent to which scheduled outages of the Qualifying Facility can be usefully coordinated with scheduled outages of the utility's facilities; (C)

   e. The usefulness of energy and capacity supplied from a Qualifying Facility during system emergencies, including its ability to separate its load from its generation;

   f. The individual and aggregate value of energy and capacity from Qualifying Facilities on the electric utility's system; and

   g. The smaller capacity increments and the shorter lead times available with additions of capacity from Qualifying Facilities; and (C)

3. The relationship of the availability of energy or capacity from the Qualifying Facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a Qualifying Facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

The guidelines for negotiating a Non-Standard Contract are more specifically described later in this schedule in GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD.

Off Peak Hours are the daily hours from hour ending 2300-0600 Mountain Time (8 hours), plus all other hours on all Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (C)(M)

On Peak Hours are the daily hours from hour ending 0700-2200 Mountain Time, (16 hours) excluding all hours on all Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (C)(M)

Point of Delivery means for off-system Qualifying Facilities, the point on the Company's distribution or transmission system where the QF and Company have agreed the QF will deliver energy to the Company. For on-system QFs, the Point of Delivery is the Point of Interconnection. (C) (C) (C)

Point of Interconnection means the point where the QF is electrically connected to the Company's transmission or distribution system. (C) (C)

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

Qualifying Facility or QF is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Seasonality Factor is the factor used in determining the seasonal purchase price of energy. The applicable factors are:

73.50% for Season 1 (March, April, May);
120.00% for Season 2 (July, August, November, December);
100.00% for Season 3 (June, September, October, January, February).

Seller is any entity that owns or operates a Qualifying Facility and desires to sell Net Output to the Company. (C)

Standard Contracts are the pro forma Energy Sales Agreements the Company maintains on file with the Public Utility Commission of Oregon for Intermittent and non-intermittent on-system Qualifying Facilities and Intermittent and non-intermittent off-system Qualifying Facilities, with a Nameplate Capacity Rating which meets the Eligibility Threshold. (C)

Station Service is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller. (C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS

There are two separate processes required for a Seller to deliver and sell Net Output from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.

1. Generation Interconnection Process

All generation projects physically interconnecting to the Company's electrical system, regardless of size, location or ownership, must successfully complete the Generation Interconnection Process prior to the project delivering Net Output to the Company. A complete description of the Small Generator Interconnection Procedures, the Interconnection Application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Load Serving Operations at 1-208-388-2658 for further information. (C) (C)

All generation projects delivering power under the off-system Energy Sales Agreement must successfully complete a comparable Generation Interconnection Process with the Seller's host interconnection provider and transmission provider.

2. Energy Sales Agreement

To begin the process of completing a Standard Contract or negotiating a Non-Standard Contract, for a proposed project, the Seller must submit to the Company a request for an Energy Sales Agreement. All requests will be processed in the order of receipt by the Company.

a. Communications

Unless otherwise directed by the Company, all communications to the Company regarding an Energy Sales Agreement should be directed in writing as follows:

Idaho Power Company
Cogeneration and Small Power Production
P O Box 70
Boise, Idaho 83707

b. Procedures

i. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

ii. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number
d) Demonstration that the Qualifying Facility meets the Eligibility Threshold described above and set forth in OAR 860-029-0045 (C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

b. Procedures (Continued)

e) Demonstration of ability to obtain certified qualifying facility status prior to commercial operation; for QFs larger than 1 MW, a Form 556 self-certification of the proposed QF or a FERC order granting an application for certification of the proposed qualifying facility is required (N)
f) Copy of the FERC license (applicable to hydro projects only)
g) Location of the proposed project including general area, specific legal property description, longitude and latitude, and site layout (C)
h) Description of the proposed project including specific equipment models, types, sizes and configurations
i) Type of project (wind, hydro, geothermal etc.)
j) Motive force or fuel plan
k) Nameplate Capacity Rating of the proposed project (N)
l) Schedule 85 pricing option selected
m) Desired term of the Energy Sales Agreement
n) Annual Net Output amount, including an estimate of Station Service requirements and Net Output to be delivered to the Company (N)
o) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable
p) Estimated first energy date
q) Estimated operation date
r) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration
s) An executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required
t) Documentary evidence that the QF has taken meaningful steps to seek site control of the proposed location of the QF including, but not limited to, documentation demonstrating:
    1. An ownership of, a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the QF;
    2. An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the QF; or
    3. Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the QF, such as an executed agreement to negotiate an option to lease or purchase the site.
u) For a QF with a battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration, and Net Output (N)

iii. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2 the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

b. Procedures (Continued)

iv. After receipt of a draft Energy Sales Agreement, the Seller may submit written comments to the Company regarding the draft agreement or request that the Company prepare a final executable Energy Sales Agreement. (N)

v. If the Seller submits comments to the Company or asks for revisions to the draft Energy Sales Agreement, in writing, the Company has 10 business days to:

(a) Notify the Seller it cannot make the requested changes;

(b) Notify the Seller it does not understand the requested changes or requires additional information; or

(c) Provide a revised draft Energy Sales Agreement. However, the Company will have 15 business days to respond or provide a revised draft Energy Sales Agreement when the Seller requests a change to the Point of Delivery. (N)
(D)

vi. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare an executable Energy Sales Agreement. In connection with such request, the Seller must provide the Company any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of an executable Energy Sales Agreement. Once the Company has received the written request for an executable Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of an executable Energy Sales Agreement, the Company will provide Seller with an executable Energy Sales Agreement within 10 business days. (C) (C) (C) (C) (C)

vii. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement within five business days. Following the Company's execution, a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties (D) (C)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST PRICE
Standard Avoided Cost Prices for Baseload QF

(M)

Year	On-Peak	Off-Peak
	$/MWh	$/MWh
	(a)	(b)
2023	$116.25	$81.19
2024	$54.14	$38.51
2025	$56.27	$40.28
2026	$59.61	$43.25
2027	$68.43	$51.70
2028	$65.45	$48.33
2029	$64.35	$46.83
2030	$63.83	$45.91
2031	$64.56	$46.23
2032	$65.90	$47.15
2033	$67.84	$48.66
2034	$71.52	$51.89
2035	$73.95	$53.87
2036	$75.23	$54.69
2037	$76.77	$55.76
2038	$78.33	$56.84
2039	$80.02	$58.04
2040	$84.31	$61.82
2041	$87.07	$64.06
2042	$88.94	$65.40
2043	$91.38	$67.30
2044	$95.93	$71.30
2045	$99.73	$74.53
2046	$102.27	$76.49
2047	$105.37	$78.99

Notes:
(a) 2023: On-peak Market Prices; 2024-2047: On-peak capacity value of the Proxy Baseload resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.
(b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

Standard Avoided Cost Prices with Integration Charges for a Wind QF (M)

Year	On-Peak ($/MWh) (a)	Off-Peak $/MWh (b)	Wind Integration Charge $/MWh (c)	On-Peak with Integration Charge $/MWh (d) (a)-(c)	Off-Peak with Integration Charge $/MWh (e) (b)-(c)
2023	$116.25	$81.19	$0.83	$115.42	$80.36
2024	$44.39	$38.51	$0.85	$43.54	$37.66
2025	$46.29	$40.28	$0.87	$45.42	$39.41
2026	$49.40	$43.25	$0.89	$48.51	$42.36
2027	$57.99	$51.70	$0.91	$57.08	$50.79
2028	$54.77	$48.33	$0.93	$53.84	$47.40
2029	$53.41	$46.83	$0.95	$52.46	$45.88
2030	$52.65	$45.91	$0.97	$51.68	$44.94
2031	$53.12	$46.23	$0.99	$52.13	$45.24
2032	$54.20	$47.15	$1.02	$53.18	$46.13
2033	$55.87	$48.66	$1.04	$54.83	$47.62
2034	$59.27	$51.89	$1.06	$58.21	$50.83
2035	$61.42	$53.87	$1.09	$60.33	$52.78
2036	$62.41	$54.69	$1.11	$61.30	$53.58
2037	$63.66	$55.76	$1.14	$62.52	$54.62
2038	$64.92	$56.84	$1.16	$63.76	$55.68
2039	$66.30	$58.04	$1.19	$65.11	$56.85
2040	$70.27	$61.82	$1.22	$69.05	$60.60
2041	$72.71	$64.06	$1.25	$71.46	$62.81
2042	$74.25	$65.40	$1.28	$72.97	$64.12
2043	$76.35	$67.30	$1.30	$75.05	$66.00
2044	$80.56	$71.30	$1.33	$79.23	$69.97
2045	$84.00	$74.53	$1.37	$82.63	$73.16
2046	$86.18	$76.49	$1.40	$84.78	$75.09
2047	$88.91	$78.99	$1.43	$87.48	$77.56

Notes
(a) 2023 On-Peak Market Prices; 2024-2047: Value of on-peak capacity allocated to on-peak hours of a Wind resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.
(b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.
(c) Wind Integration Charges based on current penetration level of 727-1397 MW. The integration charge will be updated when the next penetration level is reached. (M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

Standard Avoided Cost Prices with Integration Charges for a PV Solar QF

M

Year	On-Peak	Off-Peak	PV Solar Integration Charge	On-Peak with Integration Charge	Off-Peak with Integration Charge
	($/MWh)	$/MWh	$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d) (a)-(c)	(e) (b)-(c)
2023	$116.25	$81.19	$4.13	$112.12	$77.06
2024	$42.62	$38.51	$4.23	$38.39	$34.28
2025	$44.48	$40.28	$4.32	$40.16	$35.96
2026	$47.55	$43.25	$4.42	$43.13	$38.83
2027	$56.10	$51.70	$4.53	$51.57	$47.17
2028	$52.83	$48.33	$4.63	$48.20	$43.70
2029	$51.43	$46.83	$4.74	$46.69	$42.09
2030	$50.62	$45.91	$4.85	$45.77	$41.06
2031	$51.05	$46.23	$4.96	$46.09	$41.27
2032	$52.08	$47.15	$5.07	$47.01	$42.08
2033	$53.70	$48.66	$5.19	$48.51	$43.47
2034	$57.05	$51.89	$5.31	$51.74	$46.58
2035	$59.15	$53.87	$5.43	$53.72	$48.44
2036	$60.09	$54.69	$5.55	$54.54	$49.14
2037	$61.28	$55.76	$5.68	$55.60	$50.08
2038	$62.49	$56.84	$5.81	$56.68	$51.03
2039	$63.82	$58.04	$5.95	$57.87	$52.09
2040	$67.73	$61.82	$6.08	$61.65	$55.74
2041	$70.11	$64.06	$6.22	$63.89	$57.84
2042	$71.59	$65.40	$6.37	$65.22	$59.03
2043	$73.63	$67.30	$6.51	$67.12	$60.79
2044	$77.77	$71.30	$6.66	$71.11	$64.64
2045	$81.15	$74.53	$6.81	$74.34	$67.72
2046	$83.27	$76.49	$6.97	$76.30	$69.52
2047	$85.92	$78.99	$7.13	$78.79	$71.86

Notes:

(a) 2023 On-Peak Market Prices; 2024-2047: Value of on-peak capacity allocated to on-peak hours of a PV Solar resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(c) Solar Integration Charges based on current penetration level of 562-1355 MW. The integration charge will be updated when the next penetration level is reached.

M

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET OUTPUT PURCHASE PRICE (Continued) (C)

For contract years one (1) through (15) fifteen, the monthly Net Output Purchase Price will be calculated as follows: (C)

For all Net Output delivered to the Company on a monthly basis during On Peak hours the Net Output Purchase Price will be: (C) (C)

The On-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor.

For all Net Output delivered to the Company on a monthly basis during Off Peak hours the Net Output Purchase Price will be: (C) (C)

The Off-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor.

For all periods after the end of the fifteenth (15^{th}) contract year, the Company will pay the Seller monthly, for Net Output delivered and accepted at the Point of Delivery in accordance with the Seller's election of the following options: (C) (C)

Option 1 – Dead Band Method

Net Output Purchase Price = (C)

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor
Off-Peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) =
90% of Fuel Cost if
Indexed Fuel Cost is less than 90% Fuel Cost; else
110% of Fuel Cost if
Indexed Fuel Cost is greater than 110% Fuel Cost; else
Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net Output deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET OUTPUT PURCHASE PRICE (Continued) (C)

Option 2 – Gas Market Method

Net Output Purchase Price = (C)

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor
Off-Peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net Output deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

(D)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD

1. The Company will not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement and the Company's Standard Contracts are useful starting points in negotiating QF agreements.

2. The Company will provide an indicative pricing proposal for a QF that plans to provide Firm Energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The Company will provide an indicative pricing proposal within 30 days of receipt of the information the Company requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

   a. The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for negotiated contracts, as refined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages. (C)

   b. The prospective QF may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations. The Company may require additional information from the QF necessary to prepare a draft agreement.

   c. Within 30 days of receiving the required information, the Company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

   d. The QF must submit in writing a statement of its intention to begin negotiations with the Company and may include written comments and proposals. The Company is not obligated to begin negotiations until it receives written notification from the QF. The Company will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the QF may file a complaint with the Oregon Public Utility Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

3. QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

4. The Company should consider the QF to be providing Firm Energy or capacity if the contract requires (C)
delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. The Company shall not determine that a QF provides no capacity value simply because the Company did not select it through a competitive bidding process. For a QF providing Firm Energy or capacity: (C)

a. The Company and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the Company's partial requirements tariffs as guidance.

b. The QF should be required to make best efforts to meet its capacity obligations during Company system emergencies.

c. The Company and the QF should negotiate security, default, damage and termination provisions that keep the Company and its ratepayers whole in the event the QF fails to meet obligations under the contract.

d. Delay of commercial operation should not be a cause of termination if the Company determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

f. The Company should include a provision in the contract that states the Company may require a QF terminated due to its default and wishing to resume selling to the Company be subject to the terms of the original contract until its end date.

5. An "as available" obligation for delivery of energy, including deliveries in excess of Nameplate Capacity Rating or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm (C)
commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

6. For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.

7. When QF rates are based on avoided costs calculated at the time of delivery, the Company should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

   a. For QFs providing Firm Energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases. (C)

   b. For QFs providing energy on an “as available” basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

8. The Company should not make adjustments to standard avoided cost rates other than those approved by the Oregon Public Utility Commission and consistent with these guidelines.

9. The Company should make adjustments to avoided costs for reliability on an expected forward-looking basis. The Company should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

10. The Company should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

11. If avoided cost rates for a QF are calculated at the time of the obligation and the Company’s avoided resource is a fossil fuel plant, the Company should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

12. Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the Company’s system, unless the QF contracts for integration services with a third party.

   a. The Company should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

   b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the Company proxy plant.

   c. The Company should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the Company expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be Intermittent resources

13. The Company should adjust avoided cost rates for QF line losses relative to the Company proxy plant based on a proximity-based approach.

14. The Company should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QFs location relative to the Company proxy plant and adjust avoided cost rates accordingly.

15. The Company should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

16. The Company should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

17. Regarding Surplus Sale and Simultaneous Purchase and Sale:

a. QFs may either contract with the Company for a “surplus sale” or for a “simultaneous purchase and sale” provided, however, that the QFs selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the Company then in effect or any agreement between the QF and the Company;

b. The two sale/purchase arrangements described in paragraph 17.a will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the “simultaneous purchase and sale” is not available to QFs not directly connected to the Company’s electrical system;

c. The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph 17. a; and (C)

d. The avoided cost calculations by the Company do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph 17.a., rather than the other.

Idaho Power's

Revised Schedule 85

REDLINE

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES

AVAILABILITY

Service under this schedule is available for power delivered to the Company's control area within the State of Oregon by a Qualifying Facility (QF). (C)

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1. Owns or operates a Qualifying Facility meeting the Eligibility Threshold defined below and desires to sell Net Output ~~Energy~~generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract; (C)

2. Meets all applicable requirements of the Company's Generation Interconnection Process.

For Qualifying Facilities with a Nameplate Capacity ~~r~~Rating greater than 10 MW, a negotiated Non-Standard Contract between the Seller and the Company is required. (C)

DEFINITIONS

Eligibility Threshold is the Nameplate Capacity Rating requirement of a Qualifying Facility in order to be eligible for the terms and conditions of the Standard Contract. The separate Eligibility Threshold delineations are: (C)

1. For all solar QF projects:
   a. With a Nameplate Capacity Rating no greater than 3 MW – the project is eligible for a Standard Contract with fixed terms and standard avoided cost prices; (C)
   b. With a Nameplate Capacity Rating above 3 MW and less than or equal to 10 MW – the project is eligible for a Standard Contract with fixed terms and negotiated avoided cost prices; (C)
2. For all non-solar QF projects with a Nameplate Capacity Rating of 10 MW or less – the project is eligible for a Standard Contract with fixed terms and standard avoided cost prices. (C)

Energy means the electric energy, expressed in kWh~~,~~. ~~generated by the Qualifying Facility and delivered by the Seller to the Company in accordance with the conditions of this schedule and the Standard Contract. Energy is measured net of Losses and Station Use.~~ (D) (N)

Energy Sales Agreement means the power purchase agreement between the Company and the Seller. (N)

FERC means the Federal Energy Regulatory Commission. (N)

Firm Energy means a specified quantity of energy committed by a QF to the Company.

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards. The Generation Interconnection Process is managed by the Company's Load Serving Operations~~Delivery Business Unit~~. (C)

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1,000.

~~Heavy Load (HL) Hours are the daily hours from hour ending 0700-2200 Mountain Time, (16 hours) excluding all hours on all Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.~~ ~~(C)~~

Intermittent describes a Qualifying Facility that produces electrical energy from the use of wind, solar or run of river hydro as the prime mover.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

~~Light Load (LL) Hours are the daily hours from hour ending 2300-0600 Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.~~ (C)

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

Nameplate Capacity Rating means maximum installed instantaneous power production capacity of the completed QF, expressed in MW (AC), and measured at the Point of Interconnection when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, and energy storage devices where relevant.~~the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt amperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device~~ (C) (C)

Net Output means all energy and capacity produced by the Qualifying Facility, less Station Service, Losses, and other adjustments, flowing through the Point of Interconnection. (C)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a ~~n~~Nameplate ~~c~~Capacity ~~r~~Raating which does not meet the Eligibility Threshold and desires to sell Energy generated by the Qualifying Facility to the Company. The starting point for negotiation of price is the ~~A~~avoided ~~C~~cost ~~C~~components established in this schedule and may be modified to address specific factors mandated by federal and state law, including (C)

1. The utility's system cost data;
2. The availability of capacity or energy from a Qualifying Facility during the system daily and seasonal peak periods, including: (C) (C)
    a. The ability of the utility to dispatch the ~~q~~Qualifying ~~f~~Facility;
    b. The expected or demonstrated reliability of the Q~~q~~ualifying F~~f~~acility;
    c. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for non-compliance; (C)
    d. The extent to which scheduled outages of the ~~q~~Qualifying F~~f~~acility can be usefully coordinated with scheduled outages of the utility's facilities;
    e. The usefulness of energy and capacity supplied from a ~~q~~Qualifying ~~f~~Facility during system emergencies, including its ability to separate its load from its generation;
    f. The individual and aggregate value of energy and capacity from ~~q~~Qualifying ~~f~~Facilities on the electric utility's system; and (C)
    g. The smaller capacity increments and the shorter lead times available with additions of capacity from Q~~q~~ualifying ~~f~~Facilities; and

3. The relationship of the availability of energy or capacity from the Qualifying Facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a Qualifying Facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

~~4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a Qualifying Facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.~~

The guidelines for negotiating a Non-Standard Contract are more specifically described later in this schedule in GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD. (C)(M)

~~Light Load (LL) Hours~~Off Peak Hours are the daily hours from hour ending 2300-0600 Mountain Time (8 hours), plus all other hours on all Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (C)(M)

~~Heavy Load (HL)~~On Peak Hours are the daily hours from hour ending 0700-2200 Mountain Time, (16 hours) excluding all hours on all Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (C) (C)

(C)

Point of Delivery means for off-system Qualifying Facilities, the point on the Company's distribution or transmission system where the QF and Company have agreed the QF will deliver energy to the Company. For on-system QFs, the Point of Delivery is the Point of Interconnection~~is the location where the Company's and the Seller's electrical facilities are inter-connected or where the Company's and the Seller's host transmission provider's electrical facilities are interconnected~~. (C) (C)

Point of Interconnection means the point where the QF is electrically connected to the Company's transmission or distribution system.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

Qualifying Facility or QF is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Seasonality Factor is the factor used in determining the seasonal purchase price of energy. The applicable factors are: (C)

73.50% for Season 1 (March, April, May);
120.00% for Season 2 (July, August, November, December);
100.00% for Season 3 (June, September, October, January, February).

Seller is any entity that owns or operates a Qualifying Facility and desires to sell ~~Energy~~ Net Output to the Company. (C)

Standard Contracts are the pro forma Energy Sales Agreements the Company maintains on file with the Public Utility Commission of Oregon for Intermittent and non-intermittent on-system Qualifying Facilities and Intermittent (C) and non-intermittent off-system Qualifying Facilities, with a Nameplate Capacity Rating which meets the Eligibility Threshold.

Station ~~Use~~ Service is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller.

~~QUALIFYING FACILITY INFORMATION INQUIRY PROCESS~~

~~There are two separate processes required for a Seller to deliver and sell energy from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.~~

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS

There are two separate processes required for a Seller to deliver and sell Net Output from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.
~~QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)~~

1. Generation Interconnection Process

All generation projects physically interconnecting to the Company's electrical system, regardless of size, location or ownership, must successfully complete the Generation Interconnection Process prior to the project delivering ~~energy~~ Net Output to the Company. A complete description of the Small Generator Interconnection Procedures, the Interconnection Application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Load Serving Operations~~Delivery Business Unit~~ at 1-208-388-2658 for further information. (C) (C)

All generation projects delivering power under the off-system Energy Sales Agreement must successfully complete a comparable Generation Interconnection Process with the Seller's host interconnection provider and transmission provider.

2. Energy Sales Agreement

To begin the process of completing a Standard Contract or negotiating a Non-Standard Contract, for a proposed project, the Seller must submit to the Company a request for an Energy Sales Agreement. All requests will be processed in the order of receipt by the Company.

a. Communications

Unless otherwise directed by the Company, all communications to the Company regarding an Energy Sales Agreement should be directed in writing as follows:

Idaho Power Company
Cogeneration and Small Power Production
P O Box 70
Boise, Idaho 83707

b. Procedures

i. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

ii. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number

(C)

d) Demonstration~~Verification~~ that the Qualifying Facility meets the ~~"~~Eligibility Threshold described above and set forth in OAR 860-029-0045~~for Standard Rates and Contract" criteria~~

~~e) Copy of the Qualifying Facility's QF certificate~~

~~n) Maximum capacity of the Qualifying Facility~~
~~o) Estimated first energy date~~
~~p) Estimated operation date~~
~~q) Point of Delivery~~
~~r) Status of the Generation Interconnection Process~~

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

b. Procedures (Continued)

e) Demonstration of ability to obtain certified qualifying facility status prior to commercial operation; for QFs larger than 1 MW, a Form 556 self-certification of the proposed QF or a FERC order granting an application for certification of the proposed qualifying facility is required ~~(C)~~ ~~(C)~~

f) Copy of the FERC license (applicable to hydro projects only)

g) Location of the proposed project including general area, ~~and~~ specific legal property description, longitude and latitude, and site layout ~~(C)~~

h) Description of the proposed project including specific equipment models, types, sizes and configurations ~~(C)~~

i) Type of project (wind, hydro, geothermal etc.)

j) Motive force or fuel plan (N)

~~j~~k) Nameplate ~~c~~Capacity Rating of the proposed project

~~k~~l) Schedule 85 pricing option selected

~~l~~m) Desired term of the Energy Sales Agreement (N)

~~m~~n) Annual Net Output ~~net energy~~ amount, including an estimate of Station Service requirements and Net Output to be delivered to the Company ~~(C)~~

o) Non-binding estimate of 12 x 24 delivery schedule and 8760 generation profile when practicable ~~(C)~~

p) Estimated first energy date

q) Estimated operation date

r) Point of Delivery as well as Point of Interconnection or multiple Points of Interconnection under consideration ~~(N)~~

s) An executed standard form of interconnection study agreement and evidence that all related interconnection study application fees have been paid, or evidence that no study is required ~~(N)~~

t) Documentary evidence that the QF has taken meaningful steps to seek site control of the proposed location of the QF including, but not limited to, documentation demonstrating:

1. An ownership of, a leasehold interest in, or a right to develop, a site of sufficient size to construct and operate the QF;
2. An option to purchase or acquire a leasehold interest in a site of sufficient size to construct and operate the QF; or
3. Another document that clearly demonstrates the commitment of the grantor to convey sufficient rights to the developer to occupy a site of sufficient size to construct and operate the QF, such as an executed agreement to negotiate an option to lease or purchase the site.

u) For a QF with a battery storage system, description of the storage design capacity, description of technology used by battery storage system, storage system duration, and Net Output

iii. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2 the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

b. Procedures (Continued)

iv. After receipt of a draft Energy Sales Agreement, the Seller may submit written comments to the Company regarding the draft agreement or request that the Company prepare a final executable Energy Sales Agreement. (N)

v. If the Seller submits comments to the Company or asks for revisions to the draft Energy Sales Agreement, in writing, the Company has 10 business days to:

(a) Notify the Seller it cannot make the requested changes;

(b) Notify the Seller it does not understand the requested changes or requires additional information; or

(c) Provide a revised draft Energy Sales Agreement. However, the Company will have 15 business days to respond or provide a revised draft Energy Sales Agreement when the Seller requests a change to the Point of Delivery. (N)

(D)

~~iv. The Company will respond within 15 business days to any written comments and proposals that the Seller provides in response to the draft Energy Sales Agreement.~~

(C)

vi. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare an executable ~~a final draft~~ Energy Sales Agreement. In connection with such request, the Seller must provide the Company ~~with an updated status of the Generation Interconnection Process which indicates that the Seller's provided information (i.e. first energy date, operation date, etc.) are realistically attainable and~~ any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of an executable ~~of a final draft~~ Energy Sales Agreement. Once the Company has received the written request for an executable~~a final draft~~ Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of an executable ~~final draft~~ Energy Sales Agreement, the Company will provide Seller with an executable ~~final draft~~ Energy Sales Agreement within 1~~5~~0 business days. (C) (C) (C) (C) (C) (D) (C)

vii. ~~After reviewing the final draft Energy Sales Agreement, the Seller may either prepare another set of written comments and proposals or approve the final draft Energy Sales Agreement. If the Seller prepares written comments and proposals, the Company will respond within 15 business days to those comments and proposals.~~

~~vii. When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement.~~ Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement within five business days. Following the Company's execution, a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST PRICE
Standard Avoided Cost Prices for Baseload QF

Year	On-Peak $/MWh (a)	Off-Peak $/MWh (b)
2023	$116.25	$81.19
2024	$54.14	$38.51
2025	$56.27	$40.28
2026	$59.61	$43.25
2027	$68.43	$51.70
2028	$65.45	$48.33
2029	$64.35	$46.83
2030	$63.83	$45.91
2031	$64.56	$46.23
2032	$65.90	$47.15
2033	$67.84	$48.66
2034	$71.52	$51.89
2035	$73.95	$53.87
2036	$75.23	$54.69
2037	$76.77	$55.76
2038	$78.33	$56.84
2039	$80.02	$58.04
2040	$84.31	$61.82
2041	$87.07	$64.06
2042	$88.94	$65.40
2043	$91.38	$67.30
2044	$95.93	$71.30
2045	$99.73	$74.53
2046	$102.27	$76.49
2047	$105.37	$78.99

(~~C~~M)

Notes:

(a) 2023: On-peak Market Prices; 2024-2047: On-peak capacity value of the Proxy Baseload resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(~~C~~M)

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

Standard Avoided Cost Prices with Integration Charges for a Wind QF

Year	On-Peak ($/MWh) (a)	Off-Peak $/MWh (b)	Wind Integration Charge $/MWh (c)	On-Peak with Integration Charge $/MWh (d) (a)-(c)	Off-Peak with Integration Charge $/MWh (e) (b)-(c)
2023	$116.25	$81.19	$0.83	$115.42	$80.36
2024	$44.39	$38.51	$0.85	$43.54	$37.66
2025	$46.29	$40.28	$0.87	$45.42	$39.41
2026	$49.40	$43.25	$0.89	$48.51	$42.36
2027	$57.99	$51.70	$0.91	$57.08	$50.79
2028	$54.77	$48.33	$0.93	$53.84	$47.40
2029	$53.41	$46.83	$0.95	$52.46	$45.88
2030	$52.65	$45.91	$0.97	$51.68	$44.94
2031	$53.12	$46.23	$0.99	$52.13	$45.24
2032	$54.20	$47.15	$1.02	$53.18	$46.13
2033	$55.87	$48.66	$1.04	$54.83	$47.62
2034	$59.27	$51.89	$1.06	$58.21	$50.83
2035	$61.42	$53.87	$1.09	$60.33	$52.78
2036	$62.41	$54.69	$1.11	$61.30	$53.58
2037	$63.66	$55.76	$1.14	$62.52	$54.62
2038	$64.92	$56.84	$1.16	$63.76	$55.68
2039	$66.30	$58.04	$1.19	$65.11	$56.85
2040	$70.27	$61.82	$1.22	$69.05	$60.60
2041	$72.71	$64.06	$1.25	$71.46	$62.81
2042	$74.25	$65.40	$1.28	$72.97	$64.12
2043	$76.35	$67.30	$1.30	$75.05	$66.00
2044	$80.56	$71.30	$1.33	$79.23	$69.97
2045	$84.00	$74.53	$1.37	$82.63	$73.16
2046	$86.18	$76.49	$1.40	$84.78	$75.09
2047	$88.91	$78.99	$1.43	$87.48	$77.56

(~~C~~M)

Notes
- (a) 2023 On-Peak Market Prices; 2024-2047: Value of on-peak capacity allocated to on-peak hours of a Wind resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.
- (b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.
- (c) Wind Integration Charges based on current penetration level of 727-1397 MW. The integration charge will be updated when the next penetration level is reached.

SCHEDULE 85
COGENERATION AND SMALL POWER PRODUCTION STANDARD CONTRACT RATES
(Continued)

Standard Avoided Cost Prices with Integration Charges for a PV Solar QF M

Year	On-Peak	Off-Peak	PV Solar Integration Charge	On-Peak with Integration Charge	Off-Peak with Integration Charge
	($/MWh)	$/MWh	$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d) (a)-(c)	(e) (b)-(c)
2023	$116.25	$81.19	$4.13	$112.12	$77.06
2024	$42.62	$38.51	$4.23	$38.39	$34.28
2025	$44.48	$40.28	$4.32	$40.16	$35.96
2026	$47.55	$43.25	$4.42	$43.13	$38.83
2027	$56.10	$51.70	$4.53	$51.57	$47.17
2028	$52.83	$48.33	$4.63	$48.20	$43.70
2029	$51.43	$46.83	$4.74	$46.69	$42.09
2030	$50.62	$45.91	$4.85	$45.77	$41.06
2031	$51.05	$46.23	$4.96	$46.09	$41.27
2032	$52.08	$47.15	$5.07	$47.01	$42.08
2033	$53.70	$48.66	$5.19	$48.51	$43.47
2034	$57.05	$51.89	$5.31	$51.74	$46.58
2035	$59.15	$53.87	$5.43	$53.72	$48.44
2036	$60.09	$54.69	$5.55	$54.54	$49.14
2037	$61.28	$55.76	$5.68	$55.60	$50.08
2038	$62.49	$56.84	$5.81	$56.68	$51.03
2039	$63.82	$58.04	$5.95	$57.87	$52.09
2040	$67.73	$61.82	$6.08	$61.65	$55.74
2041	$70.11	$64.06	$6.22	$63.89	$57.84
2042	$71.59	$65.40	$6.37	$65.22	$59.03
2043	$73.63	$67.30	$6.51	$67.12	$60.79
2044	$77.77	$71.30	$6.66	$71.11	$64.64
2045	$81.15	$74.53	$6.81	$74.34	$67.72
2046	$83.27	$76.49	$6.97	$76.30	$69.52
2047	$85.92	$78.99	$7.13	$78.79	$71.86

Notes:

(a) 2023 On-Peak Market Prices; 2024-2047: Value of on-peak capacity allocated to on-peak hours of a PV Solar resource plus Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(b) 2023 Off-Peak Market Prices; 2024-2047: Fuel and Capitalized Energy Cost of the Proxy Baseload resource.

(c) Solar Integration Charges based on current penetration level of 562-1355 MW. The integration charge will be updated when the next penetration level is reached. M

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ~~ENERGY~~ OUTPUT PURCHASE PRICE (Continued) (C)

For contract years one (1) through (15) fifteen, the monthly Net ~~Energy~~ Output Purchase Price will be calculated as follows: (C)

(C)
For all ~~Energy~~ Net Output delivered to the Company on a monthly basis during On Peak ~~HL~~ hours the Net ~~Energy~~ Output Purchase Price will be: (C)

The On-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor.

(C)
For all ~~Energy~~ Net Output delivered to the Company on a monthly basis during Off Peak~~LL~~ hours the Net ~~Energy~~ Output Purchase Price will be: (C)

The Off-Peak price from the preceding applicable Standard Avoided Cost Price tables multiplied by the appropriate Seasonality Factor.

(C)
For all periods after the end of the fifteenth (15th) contract year, the Company will pay the Seller monthly, for ~~Energy~~ Net Output delivered and accepted at the Point of Delivery in accordance with the Seller's election of the following options: (C)

Option 1 – Dead Band Method

Net ~~Energy~~ Output Purchase Price = (C)

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor
Off-Peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) =
90% of Fuel Cost if
Indexed Fuel Cost is less than 90% Fuel Cost; else
110% of Fuel Cost if
Indexed Fuel Cost is greater than 110% Fuel Cost; else
Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net ~~Net~~ Output~~Energy~~ deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ~~ENERGY~~ OUTPUT PURCHASE PRICE (Continued) (C)

Option 2 – Gas Market Method

Net ~~Energy~~ Output Purchase Price = (C)

On-Peak = (AGPU + Capacity Payment On-Peak Hours) X Seasonality Factor
Off-Peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

On-Peak and Off-Peak are established in this schedule by QF resource type for the applicable calendar year of the actual Net ~~Energy~~ Output deliveries to the Company, and (C)

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

~~MISCELLANEOUS PROVISIONS~~ (D)

~~Insurance~~

~~Qualifying Facilities with a Nameplate Capacity of 200 kilowatts or smaller are not required to provide evidence of liability insurance.~~

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD

1. The Company will not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement and the Company's Standard Contracts are useful starting points in negotiating QF agreements.

2. The Company will provide an indicative pricing proposal for a QF that plans to provide ~~f~~Firm ~~e~~Energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The Company will provide an indicative pricing proposal within 30 days of receipt of the information the Company requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following: (C)

   a. The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for negotiated contracts, as refined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

   b. The prospective QF may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations. The Company may require additional information from the QF necessary to prepare a draft agreement.

   c. Within 30 days of receiving the required information, the Company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

d. The QF must submit in writing a statement of its intention to begin negotiations with the Company and may include written comments and proposals. The Company is not obligated to begin negotiations until it receives written notification from the QF. The Company will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

~~e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.~~

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the QF may file a complaint with the Oregon Public Utility Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

3. QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF. (C)

4. The Company should consider the QF to be providing ~~f~~Firm ~~e~~Energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. The Company shall not determine that a QF provides no capacity value simply because the Company did not select it through a competitive bidding process. For a QF providing ~~f~~Firm ~~e~~Energy or capacity: (C)

a. The Company and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the Company's partial requirements tariffs as guidance.

b. The QF should be required to make best efforts to meet its capacity obligations during Company system emergencies.

c. The Company and the QF should negotiate security, default, damage and termination provisions that keep the Company and its ratepayers whole in the event the QF fails to meet obligations under the contract.

d. Delay of commercial operation should not be a cause of termination if the Company determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

f. The Company should include a provision in the contract that states the Company may require a QF terminated due to its default and wishing to resume selling to the Company be subject to the terms of the original contract until its end date.

5. An "as available" obligation for delivery of energy, including deliveries in excess of Nameplate Capacity Rating or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes. (C)

~~6. For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.~~

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

6. For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.

7. When QF rates are based on avoided costs calculated at the time of delivery, the Company should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

   a. For QFs providing ~~f~~Firm ~~e~~Energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases. (C)

   b. For QFs providing energy on an "as available" basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

8. The Company should not make adjustments to standard avoided cost rates other than those approved by the Oregon Public Utility Commission and consistent with these guidelines.

9. The Company should make adjustments to avoided costs for reliability on an expected forward-looking basis. The Company should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

10. The Company should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

11. If avoided cost rates for a QF are calculated at the time of the obligation and the Company's avoided resource is a fossil fuel plant, the Company should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

12. Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the Company's system, unless the QF contracts for integration services with a third party.

   a. The Company should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources. ~~(C)~~

   b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the Company proxy plant.

   c. The Company should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the Company expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

~~d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.~~

~~e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.~~

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS NOT MEETING THE ELIGIBILITY THRESHOLD (Continued)

d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be Intermittent resources

13. The Company should adjust avoided cost rates for QF line losses relative to the Company proxy plant based on a proximity-based approach.

14. The Company should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QFs location relative to the Company proxy plant and adjust avoided cost rates accordingly.

15. The Company should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

16. The Company should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

17. Regarding Surplus Sale and Simultaneous Purchase and Sale:

a. QFs may either contract with the Company for a "surplus sale" or for a "simultaneous purchase and sale" provided, however, that the QFs selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the Company then in effect or any agreement between the QF and the Company;

b. The two sale/purchase arrangements described in paragraph 17.~~-~~a will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the "simultaneous purchase and sale" is not available to QFs not directly connected to the Company's electrical system;

c. The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph 17. a; and (C)

d. The avoided cost calculations by the Company do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph 17.a., rather than the other.