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A DIVISION OF PACIFICORP

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April 29, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UM 1610 – Investigation into Qualifying Facility Contracting and Pricing
Reply Testimony of PacifiCorp

PacifiCorp d/b/a Pacific Power ("PacifiCorp or the Company") encloses for filing in the above-referenced docket its reply testimony and exhibits of Brian S. Dickman, Bruce W. Griswold and Nathan R. Ortega. A CD containing the workpapers is also provided.

The Company requests that all data requests on this matter be sent to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Please contact Joelle Steward, Director of Pricing, Cost of Service and Regulatory Operations, at (503) 813-5542 for questions on this matter.

Sincerely,

William R Griffith/JS

William R. Griffith
Vice President, Regulation

Enclosure

Cc: Service List – UM 1610

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Reply Testimony in the Investigation into Qualifying Facility Contracting and Pricing on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 29th day of April 2013.

Carrie Meyer
Carrie Meyer
Supervisor, Regulatory Operations

Docket No. UM-1610
Exhibit PAC/300
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Brian S. Dickman

April 2013

Q. Are you the same Brian S. Dickman who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (the Company)?

A. Yes.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my reply testimony is to clarify PacifiCorp's original proposal regarding the proper method for calculating avoided costs and respond to various positions taken by intervenors as they impact PacifiCorp. I respond to the proposals and analyses presented by Mr. Adam Bless on behalf of Public Utility Commission of Oregon (Commission) Staff (Staff); Messrs. Don Schoenbeck, and John Lowe on behalf of Renewable Energy Coalition (REC); Mr. William Eddie on behalf of OneEnergy, Inc. (OneEnergy); Mr. Philip Carver and Ms. Kacia Brockman on behalf of the Oregon Department of Energy (ODOE); Messrs. Ormand Hilderbrand, Don Reading, and Tom Svendsen on behalf of the Community Renewable Energy Association (CREA); and Mr. Jimmy Lindsay on behalf of Renewable Northwest Project (RNP).

Q. How is your testimony organized?

A. My testimony is organized according to the issues list adopted for this phase of the proceeding.

Q. Do you have any general comments about the goals and purpose of this investigation into Qualifying Facility (QF) contracting and pricing?

A. Yes. This investigation gives the Commission the opportunity to rebalance the tradeoffs between prices paid to QFs and costs incurred by retail customers. It is a one-for-one tradeoff as every additional dollar paid to QF developers is ultimately born by retail customers. The QF developers that are parties to this docket have made proposals that increase QF prices, including adders to the QF prices that are not included in the current method, such as wheeling expenses, deferred transmission and distribution infrastructure (including PacifiCorp's Energy Gateway project), and regional pipeline infrastructure and storage costs. There is no compelling evidence that these costs are actually avoided by the addition of a QF in Oregon. Increasing QF pricing for theoretical costs that likely do not represent costs avoided by the utility as a result of QF generation is not consistent with the Public Utilities Regulatory Policies Act (PURPA) and will only serve to increase the upward price pressure on rates for the Company's retail customers.

The standard rates should be simple, transparent, and easy to administer. As described in Order No. 05-584, a lack of precision in standard rates is a deliberate balancing act, but the Company believes it is a reasonable approach if eligibility for standard rates is kept within limits that minimize the impact of imprecise prices on utility customers. Making multiple adjustments to avoided costs to account for the amorphous 'value' of QF projects strays further from the intent of PURPA and the actual costs that the Company can avoid due to the QF. This ultimately puts increased pressure on retail electric rates as customers are asked to recover the higher prices paid to QFs. The Company's proposal to limit the standard method to QFs of 3MW or less and use a model-based method for larger QFs helps to accurately reflect the realities of costs the Company faces to procure energy and capacity.

Q. Do you have any general comments reacting to other parties' testimony related to PacifiCorp?

A. Yes. Based on comments made in various pieces of testimony it seems some parties did not fully understand PacifiCorp's proposal to use a model-based approach to calculate the non-standard avoided cost rates for QFs exceeding the eligibility cap for published rates. For example, REC indicates PacifiCorp "proposed to continue the use of their modeling methods previously approved by the Commission for projects larger than the cap."[1] To be clear, PacifiCorp proposes the Commission approve two distinct methodologies for calculating avoided costs: one for small QFs (under 3 MW) eligible for published rates, and one for large QFs over the eligibility cap. Standard rates would continue to be based on the deferred proxy resource method currently in place in Oregon. Non-standard rates, however, would be based on the partial displacement differential revenue requirement (PDDRR) method that utilizes the Company's Generation and Regulation Initiative Decision Tools (GRID) production cost model to measure the impact of a QF on PacifiCorp's system net power costs. The GRID model is currently approved by the Commission for use in setting prices for retail customers and is also used to determine the direct access transition adjustment.

Q. Please summarize the remainder of your testimony.

A. My reply testimony supports the Company's positions by issue as follows:

- *Issue 1: Avoided Cost Price Calculation* – The method for calculating standard rates should be maintained, but, as described by Company witness Mr. Bruce W. Griswold, the eligibility cap should be reduced to 3

[1] CREA/200, Reading/3.

MW. The standard rates should be simple, transparent, and easy to administer. The cost of the avoided resource during the deficiency period should not be adjusted for large infrastructure investments in the electric transmission and gas transportation networks. Non-standard rates should be calculated using the PDDRR method which takes advantage of the Company's GRID model to measure the impact of a QF on PacifiCorp's system. QFs renewing existing contracts should not be given preferential treatment by including capacity payments during the resource sufficiency period. Such an approach would create a situation where QFs renewing existing contracts would be afforded a higher price than a new QF.

- *Issue 2: Renewable Avoided Price Calculation* – Renewable avoided costs should be differentiated for intermittent and non-intermittent resources. Renewable avoided costs should not include both the capacity costs of the avoided renewable resource and capacity costs of an avoided combined cycle combustion turbine (CCCT).
- *Issue 3: Schedule for Avoided Cost Price Updates* – Annual updates to the standard avoided cost price inputs would be reasonable as long as changes in the load and resource balance that affect the resource sufficiency/deficiency period are considered. Updates should occur on a fixed schedule with a certain filing date. Non-standard rates based on the PDDRR method should be based on the most current information available at the time the QF requests prices, consistent with utility practice for acquiring other large supply side resources.

- *Issue 4: Price Adjustments for Specific QF Characteristics* – Integration costs should be included in the avoided cost prices for all intermittent QFs. For PacifiCorp, avoided integration costs and incurred integration costs do not need to be split out because the two are equal to each other. Solar resources are intermittent and should be charged for integration; the most reasonable proxy available is the Company's wind integration study. The seven factors in 18 CFR § 292.304(e)(2) are best accounted for using the PDDRR method for large QFs. Standard rates should not be adjusted for perceived benefits of small QFs, and there should not be special consideration made for a subclass of smaller-sized QFs eligible for standard rates. If adjustments are made to increase standard rates, the Commission should consider other adjustments that reduce the price relative to the avoidable proxy resource.

Issue 1: Avoided Cost Price Calculation

Issue 1A: What is the most appropriate methodology for calculating avoided cost prices?

Issue 1A(i): Should the Commission retain the current method based on the cost of the next avoidable resource identified in the Company's current IRP, allow an "IRP" method based on computerized grid modeling, or some other method?

Q. Please summarize the recommendation made in your direct testimony with respect to calculating avoided cost prices.

A. The Company proposed to use two distinct methodologies for calculating avoided costs: a standard method based on a proxy resource to calculate published prices for small QFs under 3 MW on PacifiCorp's Schedule 37 (standard avoided costs), and a model-based approach that captures resource-specific characteristics and their impact on the utility system to calculate non-standard, or negotiated, avoided cost prices for larger QFs on PacifiCorp's Schedule 38 (non-standard avoided costs). Calculation of the standard avoided costs would remain largely unchanged from the current method. Non-standard avoided costs would be calculated using the Company's GRID production cost model. The PDDRR method is commonly used by the Company in its other jurisdictions to calculate non-standard avoided cost prices.

Q. Has your recommendation changed?

A. No.

Q. Did any of the parties argue that the Company's PDDRR method is not more accurate than the current method which applies discrete adjustments to the standard avoided costs?

A. Two parties, Staff and ODOE, expressed concern that model-based approaches will not necessarily result in more accurate avoided cost prices. Staff stated that adopting model-based approaches will not guarantee more accurate avoided-cost prices and that the modeled results are only as good as the inputs.[2] This is true of any analysis, including the calculation of adjustments for non-standard avoided costs approved for use today. However, utilizing the GRID model has the benefit of reflecting the unique characteristics of PacifiCorp's system and the costs that the Company (and its customers) is able to avoid with the addition of a QF.

ODOE claims that the model-based methods proposed by PacifiCorp and Idaho Power are not a more accurate assessment of the utilities' avoided costs

[2] Staff/100, Bless/9.

based on its interpretation of Commission Order No. 05-584 in Docket No. UM 1129. ODOE's criticism of the PDDRR method, which is proposed by the Company to be used to calculate the avoided cost related to large QFs, is based on an improper application of the Commission's order wherein various issues related to the calculation of standard avoided cost rates were resolved. The Commission was clear that the decisions in Order No. 05-584 applied "primarily to standard contract rates, terms and conditions for QF power"[3] and that it would consider issues pertaining to non-standard contracts in a second phase of Docket No. UM 1129. The Commission recognized that the standard avoided cost method is not an accurate calculation of the avoided costs for large QF projects, and in the next phase of Docket No. UM 1129 the Commission approved adjustments to be made to the standard avoided cost method to more accurately calculate the value of a QF to the utility.

ODOE claims that the proxy method adopted for standard avoided costs is superior to model-based approaches because the Commission struck a balance by valuing the QF energy and capacity at market during a sufficiency period and at the full cost of a new CCCT in a resource deficiency period, rather than measuring the operating costs the utility would incur in the respective periods. However, when describing this balance struck in Order No. 05-584 the Commission stated:

> "…We recognize a need to balance our interest in reducing these market barriers with our goal of ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy. With standard contracts, *project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored.* No party presented evidence in this docket that

[3] Order No. 05-584 at 2.

> the special characteristics of larger projects do not need to be considered in order to achieve rates that reflect actual avoided costs."[4] (Emphasis added.)

The Company's proposal in this case, to use the PDDRR method to calculate the avoided cost of large QF projects on PacifiCorp's system, refines the calculation of costs that PacifiCorp would incur for capacity and energy but for the addition of a large QF resource.

Q. ODOE argues that, with a model-based method, customers would pay a price to the QF that would be substantially below the value of the power. Do you agree with ODOE's analysis and conclusion?

A. No. First, ODOE ascribes additional 'value' to QF power relative to the proxy CCCT, stating that customers would be better off with QF power due to gaining resource diversity and learning about lower carbon power sources. ODOE concludes that prices calculated using production cost models would not recognize these additional benefits of QFs and, therefore, the prices would be below the value of the power. However, PURPA limits the amount paid to QFs to the incremental cost of electric energy and capacity which, but for the purchase from the QF, the utility would generate itself or purchase from another source. The PDDRR method uses a production cost model to simulate operation of the Company's system with and without the QF and therefore quantifies the net impact of the QF capacity and energy in terms of the electricity and capacity that is no longer generated or purchased by the utility.

ODOE also incorrectly concludes that PacifiCorp's PDDRR method does not consider the value of potential wholesale power sales and, consequently,

[4] Order No. 05-584 at 16.

underestimates the value to customers.[5] In fact, one of the benefits of the PDDRR method is that it utilizes two GRID runs – one with the QF and one without – which account for the additional energy and capacity provided by the QF and allows for a dynamic re-dispatch of the Company's system, including the ability to make additional wholesale power sales as a result of adding the QF to the Company's resource portfolio.

Q. Did any party recognize the advantages of using a model-based calculation for large QFs?

A. Yes. Staff "considered the fact that these model-based methods account for a greater array of costs associated with the purchase of QF power; specifically those costs avoided by the utility and actual costs incurred by the utility because of specific operating characteristics of the QF."[6] REC agreed that a model-based method "can do a better job of taking into account a utility's needs by incorporating all the expected loads and resources over the contracting planning horizon."[7] In fact, REC supports the use of a model-based approach for Idaho Power, stating it "would more precisely apply avoided costs based upon the value a specific project brings to the utility."[8]

Q. What was the overriding concern that led others to recommend not adopting a model-based method for calculating avoided costs?

A. A number of parties noted concerns that model-based approaches are not sufficiently transparent to the QF developers and their lenders. Staff indicated

[5] ODOE/100, Carver/7.
[6] Staff/100, Bless/8.
[7] Coalition/200, Schoenbeck/9.
[8] Coalition/100, Lowe/23.

transparency is its chief concern with a model-based approach. REC opposes the PDDRR method because it relies on an internally produced model that is not available or sold on the market. ODOE argues that the application of modeling methods would hamper development of QF renewable resources because modeling results are opaque and harder to predict than the current method.

Q. Do you share their concerns?

A. No. Balance between transparency and accuracy is an important consideration in avoided cost pricing, but as QF projects increase in size and developers are more sophisticated it is necessary that avoided cost prices be as accurate as possible in order to meet the standard of utility customer indifference. The potential impact of an 80 MW wind QF on PacifiCorp's system is significant – at current prices the total payments to an 80 MW wind QF would exceed $200 million over 20 years. It is essential that specific characteristics of the QF and the current value to the utility are accounted for in the calculation of costs that can truly be avoided.

PacifiCorp has gone to great lengths to facilitate review of the GRID model and make it available at no cost to intervenors and developers. It has been used to calculate net power costs for general rate cases across PacifiCorp's service territory since 2002 and has undergone extensive scrutiny by regulators and intervenors. It has also been used to produce avoided cost prices under the PDDRR methodology for QF projects in Utah, Idaho and Wyoming; PacifiCorp prepared over forty PDDRR pricing studies last year alone. Furthermore, the GRID model is used in Oregon to compute net power costs in the Company's annual Transition Adjustment Mechanism (TAM) filings and is used to calculate the transition adjustment for direct access customers.

Q. Are there similarities between developing avoided cost prices for QFs and preparing the transition adjustment for direct access customers?

A. Yes. While one addresses the impact of adding a resource to the system and the other addresses removing load from the system, they both involve tradeoffs between simplicity (proxy approach) and accuracy (production cost model-based approach). The Commission addressed these issues with respect to the transition adjustment in Docket Nos. UM 1081 and UE 179. In Docket No. UM 1081, the Commission adopted an interim transition adjustment (proxy approach) for the near-term, but asked parties to work together to find a long-term solution. Subsequently, in Docket No. UE 179, the Commission rejected the proxy approach in favor of using differential GRID runs to value the loss of the direct access load. The Company is asking the Commission to apply the differential GRID run method found prudent for valuing lost load to the acquisition of new QF resources.

Q. What policy direction did the Commission provide in Docket No. UM 1081?

A. The Commission stated that, "Ideally, a transition adjustment will value utility resources impacted by direct access based on actual, appropriate operational responses."[9] This could just as easily apply to avoided costs where, ideally, avoided cost prices will value utility resources impacted by QF resource additions based on actual, appropriate operating responses. The Commission also said its desire was to develop a transition adjustment that values resources on PacifiCorp's

[9] UM 1081, Order No. 04-516, page 10.

actual operational responses based on appropriate planning.[10] Again, this could just as easily apply to avoided cost prices where it would be desirable to develop avoided cost prices that value resources on PacifiCorp's operational responses based on appropriate planning.

Q. What did the Commission conclude in Docket No. UE 179 after setting forth policy direction in UM 1081?

A. The Commission found that using the differential GRID run approach to determine the transition adjustment proposed by PacifiCorp most closely met the requirements established in Order No. 04-516 in UM 1081.[11] The Commission went on to say, "The purpose of the TAM is not to promote direct access, as ICNU would have us do. Rather, the TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting."[12] This policy direction can be directly translated to avoided cost pricing, where the purpose of QF pricing is to capture costs avoided by adding QFs to the system and prevent unwarranted cost shifting. There is no basis for sacrificing accuracy in the development of avoided cost prices for large QFs. The Company urges the Commission to adopt a GRID-based approach to set avoided costs going forward as this would offer the most precise and accurate accounting of the impact that a new QF resource is likely to have on PacifiCorp's operations, costs and revenues.

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[10] UM 1081, Order No. 04-516, page 12.
[11] UE 179, Order No. 05-1050, page 21.
[12] Id.

Q. REC witness Mr. Schoenbeck presents a table[13] that is meant to illustrate the impact of calculating avoided costs under the current Oregon Schedule 38 Method and the PDDRR Method. Do you agree with Mr. Schoenbeck's conclusion that the differences in results are negligible?

A. No. The Company agrees that the PDDRR and the Oregon Schedule 38 method can produce similar results, but I would also note that they could be very different depending on circumstances. For an 80 MW thermal resource a one-dollar difference in avoided costs results in a change of almost $600,000 per year or just under a $12 million difference over a 20-year contract. Furthermore, Mr. Schoenbeck's table reflects only one example and does not account for the difference in avoided costs that can result from different locations or generation profiles of varying QF projects. These differences would be captured using the PDDRR method but would not be accounted for in the current Oregon Schedule 38 Method. It should also be noted that certain adjustments to the standard prices made to arrive at the Oregon Schedule 38 Method prices were prepared using the GRID model. For example, without the GRID model, the Company does not have a good way of accurately estimating the non-dispatchability adjustment used in the Oregon Schedule 38 Method.

Q. Staff proposed to adjust the standard avoided cost prices for the capacity contribution of different resource types. Do you agree with Staff's proposal?

A. No. The Company believes that multiple modifications to the standard avoided cost calculation will increase the administrative costs and complexity of updating and validating the standard avoided cost prices. The Company continues to

[13] Coalition/200, Schoenbeck/10.

recommend that the standard avoided cost calculation be maintained but with a lower eligibility cap of 3 MW.

However, the Company recommends that the capacity contribution of prospective QF resources should be taken into account in the calculation of non-standard avoided costs. Under the PDDRR method, adjusting the deferred resource for the capacity contribution of the QF properly accounts for the avoided capacity costs attributable to the QF. The Company's proposed method computes the capacity contribution of different resource technologies using five years of historical data for resources and system load. This same capacity contribution calculation was utilized to develop the Company's 2013 Integrated Resource Plan (IRP).

Q. ODOE argues that a few hundred hours is not sufficient to calculate the capacity contribution for intermittent (variable energy) resources. Do you agree?

A. No. The Company uses 100 hours per year for five years. T his is a sufficient amount of data to assess the contribution variable energy resources provide to meeting peak load. The IRP peak load and resource balance uses the single hour of peak load for planning purposes. There is no basis to claim that the use of 100 hours per year for five years (500 total hours) is insufficient.

Q. What does ODOE propose to use to determine the capacity contribution of variable energy resources?

A. ODOE proposes to use the Effective Load Carrying Capability (ELCC) method which is a theoretical method that looks at a resource's output across all hours of the year. The Company's capacity contribution study, on the other hand, uses actual data to measure the variability of output from intermittent resources across peak load hours. It makes little sense to use a theoretical method when actual data is available. Capacity from an intermittent resource should be measured based on the resource's ability to reliably satisfy the Company's peak obligations. It should not be based on a resource's ability to satisfy energy obligations in all hours of the year.

Q. Do you agree with Mr. Schoenbeck that capacity contribution of an intermittent resource should be based on its on-peak capacity factor?

A. No. The average on-peak capacity factor discussed by Mr. Schoenbeck is simply the average energy produced by the resource during on-peak hours. On-peak hours represent about 57 percent of all of the hours in a year, which is not a measure of a resources' contribution to system peak. As noted previously, the IRP uses the single hour of system coincident peak to determine how much capacity is needed to reliably operate the system.

Q. Staff recommends including avoided transmission costs in the calculation of avoided cost prices in both the standard and renewable methods. Do you agree with Staff's recommendation?

A. Staff's proposal is not directly applicable to PacifiCorp. Staff proposes to include avoided transmission costs in the standard and renewable avoided cost rates if the utility's avoided resource is an off-system resource that requires transmission to deliver energy and capacity to the utility's system.[14] PacifiCorp plans to meet its resource needs on a system-wide basis and new resources are planned to be

[14] Staff/100, Bless/6.

located on-system. The capital costs of PacifiCorp's IRP resources include the cost of connecting the resource to the Company's system, and this cost is included in the avoided capacity costs of the partially displaced resource.

Q. OneEnergy and CREA recommend that the proxy should reflect the cost to transmit power, including any necessary transmission upgrades. Do you agree with this recommendation?

A. No. There is no support for the conclusion that adding 500 MW of QFs would require less transmission than adding 500 MW of market purchases or a CCCT. Upgrades to the transmission system are needed to serve loads regardless of what kind of resource is added to the portfolio.

Q. OneEnergy claims that the costs of system upgrades necessitated by a QF are directly assigned to the QF during the interconnection process under OAR 860-082-0035(4). How do you distinguish this from system upgrades associated with a proxy resource?

A. As noted previously, system upgrades (beyond interconnection costs) are added as infrastructure to serve loads from the resources included in the Company's portfolio. Taken to its extreme, if all of the resources in the Company's portfolio were QFs, the Company would still need a transmission infrastructure to move the output of those resources to load. In addition, as previously noted, interconnection costs that are needed to connect a new resource to the transmission infrastructure are included in the CCCT costs and therefore are included in the avoided cost calculation.

Q. OneEnergy suggests that the CCCT proxy should include the cost of expanding firm natural gas pipeline capacity or storage capacity. Do you agree with this suggestion?

A. No. Natural gas pipeline capacity or storage capacity are infrastructure costs similar to transmission upgrades. Expansion of regional infrastructure may be driven by other market fundamentals besides the next avoidable CCCT, and the costs of such expansion should not be imputed to the avoidable resource when there is no support for a conclusion that the Company would otherwise incur such costs.

Q. Did any party oppose the Company's proposal to use market prices from a single market hub (Mid-C) rather than blended market prices when calculating standard avoided cost prices?

A. Most parties appear to be supportive of the Company's proposal to use the Mid-C market hub during the sufficiency period to calculate standard avoided cost prices, with the possible exception of OneEnergy. OneEnergy noted it could support the change to a single market hub only if the Company were to prepare a table "showing the annual avoided cost rates based on (a) Mid-C index only; and (b) the current blended index."[15] This information was provided along with the Company's most recent Schedule 37 filing, and I have also provided it with my reply testimony as Exhibit PAC/301. Exhibit PAC/301 illustrates that the difference between the two price streams is approximately $0.20/MWh.

[15] OneEnergy/100, Eddie/16.

Issue 1C: Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different from the market price?

Q. Please summarize the recommendation made in your direct testimony with respect to this issue.

A. In my direct testimony the Company recommended that the Commission should not adopt preferential pricing options for current QF customers seeking a renewal of a contract. Doing so would essentially extend the maximum contract length for a term longer than 20 years, which the Commission currently does not allow.

Q. Has your recommendation changed?

A. No.

Q. Staff recommends that no change be made to the current policy, in which the price schedule of a renewing contract begins with a new sufficiency period. Do you agree with Staff's assessment and conclusion?

A. Yes.

Q. Other parties argue that because existing projects have been part of a utility resource portfolio they should be treated differently than new QFs who do not have a currently executed agreement. Do you agree?

A. No. The relationship between a QF and the utility is a contractual arrangement that begins and ends with the dates set forth in the power purchase agreement. The continued operation of a QF beyond the expiration of the power purchase agreement is in the hands of the project owner. The Company has no ability to force a QF to continue operation beyond the term of the contract and a QF with an expired contract should not be given preferential treatment to a QF that is new to the system. Consequently, from the retail customer perspective there is no difference between a QF seeking to renew an existing contract and a similar QF seeking a power purchase agreement for the first time.

Q. Do you agree with REC's proposal that, as part of the IRP process, the utility should seek information from QFs with soon-to-expire contracts to evaluate the likelihood of a follow-on agreement?

A. No. Such an approach does not change the fact that the Company has no ability to ensure continued operation of a QF beyond the term of the contract.

Q. Does this conclude your reply testimony on Issue 1?

A. Yes. Company witness Mr. Griswold will provide reply testimony regarding Issues 1B and 1D.

Issue 2: Renewable Avoided Cost Price Calculation

*Issue 2A: Should there be different avoided cost prices for different renewable generation sources? (*for example *different avoided cost prices for intermittent v. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass).*

Q. Please summarize the recommendation made in your direct testimony with respect to calculating renewable avoided cost prices.

A. The Company proposed to differentiate between intermittent and base load renewable resources by including an adjustment for integration costs in the calculation of avoided cost prices for renewable QFs supplying the Company with intermittent generation. For standard avoided costs for renewable resources, rather than include multiple price streams in Schedule 37 the Company proposed to specify in the tariff that the price offered to intermittent QFs during the renewable resource sufficiency period will be reduced for the cost of integration.

Q. Has your recommendation changed?

A. No.

Q. Staff recommends that the renewable method be modified to account for the differing peak load capacity contributions of different types of QF resources. Do you agree with this approach?

A. No. The result of Staff's proposal to gross up the capacity payments included in the renewable avoided costs for a QF's capacity contribution relative to the renewable proxy produces counter-intuitive results that overstate the renewable avoided costs. Consider the example of a base load renewable QF, which is assumed to have the same capacity contribution as a CCCT in the Company's IRP. Under Staff's proposal the base load renewable QF can choose standard prices, with capacity costs equal to a CCCT starting in 2016, or standard renewable prices, with the full capacity costs of an IRP wind resource starting in 2018 *plus* 95 percent of the capacity costs of a CCCT starting in 2018. As shown in Staff/103, the adjusted standard renewable prices are significantly higher than the standard rates. On a nominal-levelized basis, the on-peak prices (which include the capacity costs) during the renewable resource deficiency period are $20/MWh higher than the standard prices for a base load QF.

Q. Why does Staff's proposal overstate the avoided cost of capacity in this way?

A. The next avoidable renewable resource in the Company's IRP – currently a utility scale wind facility – is included for reasons other capacity planning and on a capacity-adjusted basis is already more expensive than a base load CCCT. Combining the full fixed cost of a wind facility and the fixed costs of a CCCT overstates the cost of capacity on PacifiCorp's system.

Q. Does this conclude your reply testimony on Issue 2?

A. Yes. Company witness Mr. Griswold will provide reply testimony regarding Issues 2B and 2C.

<u>Issue 3: Schedule for Avoided Cost Price Updates</u>

Issue 3A: Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?

Q. Please summarize the recommendation made in your direct testimony with respect to the schedule for avoided cost updates.

A. The Company recommended that the avoided cost calculations be updated as often as practical to reflect the best available information. Updates to forward market prices for electricity and natural gas included in the standard avoided cost rates should be made on a quarterly basis in order to ensure that the published prices more closely reflect the current avoided cost to the utility. For inputs to standard avoided cost prices that are tied to the IRP, the Company recommended that the current schedule of updates at least every two years and within 30 days of acknowledgement of an IRP should be retained so long as the Company also retains the ability to update prices when there are known changes to the IRP portfolio. Furthermore, inputs to the negotiated, non-standard avoided cost prices should reflect the best available information at the time a QF requests prices.

Q. Many parties appear to support an annual update as well as an update within 30 days of IRP acknowledgment. Could the Company support this proposal?

A. Yes, as it relates to the published rates for a standard contract. The annual update should use assumptions consistent with the most recent IRP or IRP Update that is filed with the Commission. However, inputs to the PDDRR method used to calculate non-standard rates should be updated to the best available information at the time the QF requests prices.

Q. Does the Company support a date certain for an annual update for standard avoided costs?

A. Yes. If updates to the standard avoided costs are to be done on an annual basis, the Company supports a fixed filing schedule on the same date each year. A fixed schedule is a transparent trigger and alleviates any concern for gamesmanship.

Q. Does the Company agree that annual updates should be made on March 1 as suggested by Staff?

A. No. March 1 is the date the Company makes general rate case filings and its annual TAM filing in years in which it files a general rate case in Oregon. If an annual date is set, the Company recommends a date later in the year, such as in the fourth quarter, to create as few conflicts with other filings as possible.

Q. REC proposes that annual updates include only three items: market prices (both gas and electricity), execution of any new long-term contract (greater than four years) and changes in load forecasts. Do you agree with this proposal?

A. Yes, in part, for standard contracts. All three items are critical to the calculation of standard rates, but the last two – new contracts and changes in load forecasts – are only meaningful updates to the extent they influence the timing of the resource deficiency period. If the resource deficiency period cannot be updated to coincide with the changes in load and resources then having the ability to update for changes in load and contracts is not meaningful. In addition, the Company believes all signed contracts should be updated regardless of the length of the agreement. To be clear, the Company continues to maintain that inputs to the PDDRR method used to calculate non-standard rates should be updated to the best available information at the time the QF requests prices.

Q. REC argues that more frequent updates will provide an additional incentive for the utilities to impose barriers and delay the negotiating process. Do you agree?

A. No. More frequent updates will produce more accurate avoided cost prices. If a QF believes the Company is imposing barriers or delaying the negotiating process it should be addressed on a case-by-case basis.

Q. REC further argues that annual updates will resolve the criticism that the Proxy Method does not take into account changes in load forecasts or net power purchase agreements. Do you agree?

A. No. REC's proposal allows changes to the load forecast and recognition of new contracts, but it is not clear how the resulting impact to the resource deficiency period would be taken into account. REC states that the "timing of the sufficiency/deficiency period should only be allowed after or pursuant to the latest acknowledged IRP plan (or acknowledged update) with its associated public vetting or similar process."[16] It is not clear what process would be required in order to actually incorporate the changes in load forecast and contract resources and the impact on the resource deficiency period.

Q. REC proposes that an annual update be made one year from the effective date of the then-current prices. Could the Company support this proposal?

A. No. REC's proposal could mean that avoided costs may not be updated annually. The annual update filing would have to be made one year from the prior filing, not from the effective date of the prior filing, in order to keep updates timely and consistent. As stated previously, if annual updates are adopted the Company supports a fixed date for updates to be filed each year.

Q. REC also proposes that annual updates should be deferred in the event they are scheduled to occur within 90 days of when an integrated resource plan is scheduled to be acknowledged. Does the Company support this proposal?

A. No. It would be difficult for the Company to predict the Commission's issuance of an order 90 days in advance, let alone the content of the order. REC's proposal

[16] Coalition/200, Schoenbeck/15.

introduces unnecessary complication to the process that would result in additional confusion and uncertainty for QFs and utilities.

Q. REC further suggests that utilities provide notice before they file avoided cost updates. How do you react to this suggestion?

A. For standard rates, under Staff's proposal the filing date would be known in advance and notice should not be required. Non-standard rates would be determined at the time a QF requested prices, which timing is under the control of the QF.

Issue 3B: Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

Issue 3C: Should the Commission specify what factors can be updated in mid-cycle? (such as factors including but not limited to gas price or status of production tax credit)

Issue 3D: To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgment is pending be factored into the calculation of avoided cost prices?

Q. Please summarize the recommendation made in your direct testimony with respect to when mid-cycle updates are appropriate and which factors can be updated.

A. The Company recommended that the avoided cost calculations be updated as often as practical to reflect the best available information. Updates to forward market prices for electricity and natural gas included in the standard avoided cost rates should be made on a quarterly basis in order to ensure that the published prices more closely reflect the current avoided cost to the utility. The Company also proposed the Commission specify that known changes in the preferred resource portfolio should trigger an update to standard prices. Inputs to the negotiated, non-standard avoided cost prices should reflect the best available information at the time a QF requests prices.

Q. Has your recommendation changed?

A. Subject to the clarification regarding updates to standard avoided costs discussed above, the Company's recommendation has not changed.

Q. In support of maintaining the current Oregon Method, Staff asserts that forecasts and cost assumptions used should be consistent with the acknowledged IRP because those same inputs are used to inform resource acquisition decisions. Is this assertion correct?

A. No. IRP forecasts and cost assumptions are used to develop a forward-looking portfolio to serve anticipated customer demand while minimizing cost and risk. However, at the time resources are to be procured, the Company uses the most recent information available to make an acquisition decision.

Q. Do you have a recent example of where the Commission articulated this policy?

A. Yes. The Commission articulated this policy in Order No. 12-111 in Docket No. UM 1540, when it approved the Company's 2011 All Source Request for Proposals (2011 RFP) for issuance. The RFP was designed to acquire the 2016 resource identified in the Company's 2011 IRP. In that order, the Commission adopted Staff's recommendation, which conditioned the approval on the following:

> "The Company continue to evaluate the resource need under this RFP based on updated load and resource balances reflecting the results of diligently pursuing the maximum amount of cost-effective demand-side resources, maximizing front office transactions, and utilizing a 12 percent planning reserve margin."[17]

Q. Did the Company continue to evaluate the resource need prior to making a decision on the merits of acquiring a resource under the 2011 RFP?

A. Yes. During the course of the 2011 RFP, the Company updated its load forecast and used that forecast to develop a Resource Needs Assessment Update (Needs Assessment). Based on this updated information the Company found there was no longer a need to acquire a resource in 2016. The Needs Assessment was filed with the Commission on September 28, 2012, when the Company communicated to the Commission that it planned to cancel the 2011 RFP based on its new Needs Assessment. On November 16, 2012, the Company filed the final Independent Evaluator's report supporting the Company's decision. UM 1540 was closed on December 14, 2012.

Q. Did the Needs Assessment maintain the deficiency period identified in the 2011 IRP?

A. No. In fact, relying on the out-of-date information from the IRP would have resulted in the Company acquiring a resource that it did not need. Purchasing energy and capacity from a QF is no different. Use of out-of-date inputs to the avoided cost calculation will result in the Company acquiring QF resources at prices that do not reflect the Company's resource need. If avoided costs can only be based on an acknowledged IRP, new QFs selling to PacifiCorp will continue to be offered prices that include a capacity deferral credit for the canceled 2016 IRP

[17] Order No. 12-111, Appendix A, page 1.

resource until acknowledgement of the 2013 IRP, which is not expected for at least seven months after its filing or even longer given recent experience.

Q. REC contends that no updates should be allowed outside of the annual update and an update following the acknowledgment of an IRP. What are the issues with this suggestion?

A. As discussed above, not allowing updates to the IRP-based assumptions is inconsistent with how the Company evaluates the acquisitions of other resources and will result in prices paid to QFs that do not reflect costs the Company will actually avoid.

Q. Does this conclude your reply testimony on Issue 3?

A. Yes.

Issue 4: Price Adjustments for Specific QF Characteristics

Issue 4A: Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract? If so, what is the appropriate methodology?

Q. Please summarize the recommendation made in your direct testimony regarding integration of intermittent resources.

A. In my testimony the Company proposed that avoided costs should be adjusted to include the cost of integrating intermittent resources. For large QFs, those which would have prices prepared using the PDDRR method, integration costs would be calculated by year and would be included as an adjustment to reduce avoided costs. For small QFs, those priced under the standard rates, a single integration cost would be calculated and applied to all intermittent resources.

Q. Has your recommendation changed?

A. No.

Q. What does Staff recommend regarding including avoided integration costs in the calculation of avoided cost prices?

A. As I understand Staff's proposal, avoided integration costs would be added to renewable avoided costs and the QF would then be required to pay either the utility or other transmission provider's actual integration costs. In theory, a QF located within PacifiCorp's balancing authority area would net the same avoided cost payment under Staff's method as under the PacifiCorp's proposed method. In practice, though, the QF might end up receiving more or less depending on the amount of avoided integration costs added and the actual integration costs paid to the utility.

Q. Do you agree with Staff's recommendation?

A. No. One of the objectives of publishing standard avoided cost rates is to simplify the contracting process to reduce the transaction cost for small QF. Adding an additional contracting step by splitting up integration costs would be counter to that objective. PacifiCorp currently has no QF contracts with intermittent resources delivering energy from off-system locations and procuring integration services from a third party. Furthermore, on PacifiCorp's system the QF should receive the same net payment under both methods, so I see no advantage to the added complexity.

Q. CREA argues that small QFs (under 10 MW) should not be required to pay integration costs. Do you agree?

A. No. CREA argues that unspecified benefits of small projects balance out the cost of wind integration. CREA justifies its argument based on Staff's position in Docket No. UM 1129 that the standard avoided costs should not be adjusted for integration costs. However, Staff's position in that case was that the standard rates are not adjusted for *any costs or benefits* of the QF project, relative to the utility proxy plant.[18] CREA focuses on the potential benefits of small projects, but does not attempt to balance the benefits with any potential disadvantages of QF projects relative to the proxy resource. Furthermore, in Order No. 11-505 in Docket No. UM 1396 the Commission recently affirmed that the difference between intermittent and base load QFs is a distinction that should be recognized in standard avoided cost prices.

Q. How do you respond to CREA's claim that wind integration costs decrease with geographic diversity?

A. CREA cited the Northwestern Energy Montana Wind Integration study as the basis for their comments on geographic diversity. In that study Northwestern found regulating reserves decreased with geographic diversity although they were defining geographic diversity as between Madison County and Glacier County, Montana, two bookend points that are 300 miles apart. Wind added in the center between these bookend points (Wheatland County, Montana) and near Northwestern Energy's existing wind projects required greater regulating

[18] Order No. 07-360 at 24.

margin.[19] The Company's wind integration study utilizes actual operational data from PacifiCorp's fleet of generating resources, including wind projects located across its six-state system. Given PacifiCorp's expansive system, geographic diversity already influences the results of the study.

Q. ODOE proposes that standard avoided cost prices paid to wind resources should only be reduced for integration if the QF is located in the contiguous area where utilities have major wind resources and have procedures for forecasting wind project output. How do you respond to this proposal?

A. As stated above, the Company's wind integration study already accounts for the geographic diversity of PacifiCorp's fleet of wind resources. In essence, ODOE is now proposing to differentiate the cost of integration for specific geographic locations. If integration costs are lower for a QF in one area of PacifiCorp's system it implies that integration costs are higher in another area. If the Commission adopts ODOE's recommendation then the Commission should increase integration costs in what ODOE terms "the contiguous area where utilities have major wind resources."

The report cited in ODOE/102 admits, "Although the benefits of geographic diversity are generally recognized, there is insufficient information that quantifies the costs and benefits."[20] It would be especially difficult to determine specific boundaries for location-based integration costs or the appropriate cost for a given location.

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[19] Northwest Energy Montana Wind Integration Study available online at http://www.northwesternenergy.com/%5CDocuments%5CDefaultSupply%5CMTWindIntegrationStudy.pdf (last accessed April 10, 2013).
[20] ODOE/102, Carver/10.

Q. With respect to renewable avoided costs, ODOE finds that the prices paid to solar and base load renewable resources should receive an integration credit during the deficiency period. CREA also appears to argue that base load renewable resources should receive an integration credit during the deficiency period. Do you agree?

A. No. As long as the QF has the option to choose between the published standard and renewable avoided cost prices it should not also get a credit adjustment to the renewable rates for avoided integration during the deficiency period.

Q. A number of parties suggest that solar resources should not be subject to an integration charge until such an integration charge has been studied by the utility. Do you agree?

A. No. The Company disagrees that the cost to integrate solar resources be set to zero when it is clear that these resources cause such costs to be incurred. In the absence of a solar-specific study, the Company's wind integration study is the closest estimate of the cost to integrate intermittent resources on PacifiCorp's system. No party disputes that solar resources are intermittent and cause integration costs; rather, they argue that the magnitude or specific impact on PacifiCorp's system is not yet known. Despite its proposal to not allow a solar integration charge, RNP cites that the Bonneville Power Administration (BPA) has proposed to implement a solar integration charge as part of its pending rate case.

Q. Are there any factors that would lead you to believe that solar integration may be equal to or greater than wind integration rates for PacifiCorp?

A. Yes. The cost of reserves necessary to integrate solar could be equal to or greater than wind integration for the following reasons: (1) Solar resources have the potential to exhibit sharp swings in output as a result of rapidly changing cloud cover, where wind output changes more gradually. (2) Sharp changes in solar output can occur nearly instantaneously, resulting in strains on the system that may require additional reserves relative to wind. (3) Because all of the variability of solar occurs during the day, a greater portion the reserves necessary to integrate solar must be held during on-peak hours, when the opportunity cost of holding reserves is highest. (4) Correlation between load and solar generation has the potential to increase the ramping reserve requirements because of the timing of solar output relative to system load. These four factors cause the Company to believe that, despite the differences in wind and solar generation, the wind integration costs serve as a fair proxy for the cost to integrate solar resources on PacifiCorp's system.

Q. Does PacifiCorp agree that the Commission should direct the utilities to study solar integration in the next IRP cycle?

A. No. The Company does not yet have adequate data from utility-scale solar projects connected to its transmission system to perform a full solar integration study. Until such actual data is available, a solar study would have to rely on synthetic data or data from other systems with high solar penetration. Parties have been critical of utilities, including PacifiCorp, when synthetic data was used in wind integration studies.

Issue 4C: How should the seven factors of 18 CFR § 292.304(e)(2) be taken into account?

Q. Please summarize the recommendation made in your direct testimony regarding accounting for the seven factors in 18 CFR § 292.304(e)(2).

A. Adjustments for the seven factors in 18 CFR § 292.304(e)(2) are not included in the calculation of standard avoided costs, but should continue to be made for non-standard, negotiated avoided costs. The Company recommended a differential revenue requirement approach using the PDDRR method to calculate non-standard avoided costs. The PDDRR method is based on two GRID runs simulating the operation of the Company's resources with and without the QF. In addition to accounting for the interdependent nature of many of the factors listed in 18 CFR § 292.304(e)(2), the PDDRR method captures the value of additional factors such as the QF's location, delivery pattern, and capacity contribution in order to accurately calculate the avoided costs of a specific QF resource.

Q. Has your recommendation changed?

A. No.

Q. Various parties have suggested that standard avoided cost prices should be adjusted to account for perceived benefits of QF resources. Do you agree with their proposals?

A. No. Parties' proposed adjustments are generally one-sided and serve to increase avoided costs. Should the Commission choose to consider some of these upward adjustments, it should also consider downward adjustments recognizing the difference between QF projects and the avoidable resource used in the standard price calculation. For example, in Docket No. UM 1129 the Commission recognized that, for large QFs, the standard avoided costs should be adjusted for dispatchability to reflect that the QF has the right to put power to the Company in all hours even when the Company does not need the power or when the dispatchable CCCT is not economical to operate. To accurately calculate the costs that can be avoided by a particular QF, further adjustments could be made relative to the CCCT to account for the inability of a QF to provide reserves, and differences in resource availability and capacity contribution.

Q. Do you recommend that the Commission apply any or all of these adjustments to standard rates?

A. No. In Order No. 05-584 the Commission could have included a wide array of upward and downward adjustments. The Commission elected to strike a balance between adjusting the avoided cost calculation and transparency. For standard rates, I recommend that the Commission maintain the policy articulated in that order.

Q. OneEnergy and CREA propose that standard avoided costs should include a credit for resource deferral benefits similar to the benefits ascribed to Class 2 Demand Side Management (DSM) in PacifiCorp's 2011 IRP Addendum. Do you agree with this proposal?

A. No. The DSM analysis is used to identify what Class 2 DSM resources are cost effective. OneEnergy and CREA attempt to convolve this cost-effectiveness calculation into a payment calculation to QFs which would result in real dollars transferring from retail customers to QF developers. The DSM analysis was not intended to determine a payment level from the general body of retail customers to retail customers that installed DSM measures. The analogy is not appropriate.

Q. Are small QFs similar to Class 2 DSM as suggested by CREA and OneEnergy?

A. No. As defined in the Company's IRP, Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures. The result of Class 2 DSM is a sustainable and enduring reduction in retail load served by the utility. Small QFs, including distributed generation, may offset load for certain periods of time, but they do not result in a real reduction to the load the utility must be ready to serve upon demand. When a QF generator intended to offset retail load becomes unavailable, the Company must have resources available to continue serving the load. Likewise, if retail customer load peaks when the QF generation is not at its maximum availability (as is often the case with solar generation), the Company must have the transmission and distribution facilities in place to meet customer demand.

Q. OneEnergy suggests that standard avoided cost prices should be adjusted for projects under 3 MW to account for avoided transmission losses. Do you agree with this suggestion?

A. As previously discussed, adjustments to the standard avoided cost prices should not be made in either direction. Furthermore, there should not be a distinction within the standard rate schedule for benefits attributed only to projects less than 3 MW.

Q. OneEnergy also proposes that QFs eligible for the standard contract be compensated for agreeing to certain types of curtailment arrangements. Do you agree?

A. No. Prices paid under the standard contract are developed based on a dispatchable resource. To the extent a QF eligible for the standard contract is *not* dispatchable by the utility, the standard prices are already higher than they otherwise should be. This mismatch, however, is part of the accepted balance between simplicity and accuracy necessary when establishing a standard price for small QFs. The ability of a utility to dispatch a QF is important and should be considered when calculating avoided costs for large QFs. The Company's PDDRR method is intended to determine the value to PacifiCorp of a QF's specific operating characteristics.

Q. OneEnergy and CREA each propose that the renewable avoided cost should be adjusted to reflect the cost of transmission service to the utility's Oregon service territory. Do you agree?

A. No. The basis for OneEnergy's proposal is that "a remote wind project that has not secured transmission to a utility's territory in Oregon is simply not an avoided resource in Oregon."[21] However, the proposal to include transmission costs from Wyoming to the Pacific Northwest does not recognize that PacifiCorp operates its resources as a multi-state system or the fact that a portion of PacifiCorp resources and any associated renewable energy credits in any location are allocated to

[21] OneEnergy/100, Eddie/19.

Oregon customers. As previously discussed, transmission infrastructure is needed to operate PacifiCorp's system whether it adds QF or non-QF resources.

Q. CREA also proposes that the capacity factor for PacifiCorp's avoided renewable resource be adjusted to account for BPA curtailment protocols. Do you agree?

A. No. As pointed out by CREA, the Company's next avoidable renewable resource from the 2011 IRP is a Wyoming wind plant. This plant is connected directly to PacifiCorp's system and is not subject to BPA curtailment protocols.

Q. How do you respond to CREA's proposal to include an adjustment to account for increased operation and maintenance (O&M) costs for wind facilities after expiration of an initial warranty period?

A. CREA claims that O&M for the utilities' avoidable renewable resources, a wind project, should be increased $5/MWh to account for higher costs of break downs and repairs that must be covered by the owner after the initial warranty period. CREA provided no evidence, but stated it based its adjustment on the cost of securing an extended warranty. However, CREA misinterprets the IRP cost estimate; the IRP cost estimates are life-cycle costs presented in real-levelized terms for planning purposes. The IRP estimate is based on the Company's forecast for its own wind farms and includes costs associated with post-warranty parts and major component replacements. CREA also fails to recognize that the increased costs for post-warranty parts and major component repairs associated with a wind project are typically offset by lower post-warranty O&M contractor costs for routine maintenance because the O&M provider, who is typically the original equipment manufacturer, is no longer providing a warranty.

Q. CREA asserts that the federal production tax credit (PTC) should not be included in the renewable avoided cost rates. Do you agree?

A. No. CREA argues that the PTC is unlikely to be renewed so it is merely a speculative reduction to avoided costs. However, since its inception the PTC has been renewed each time it was set to expire, and there is no basis to assume the future will be different. Based on circumstances today it would be inappropriate to increase renewable avoided cost prices by over $20/MWh during the renewable deficiency period by removing a PTC that may in fact be in place in the future. The assumption of whether a PTC exists has been an important factor in whether wind projects were economically viable resources. However, given current market conditions, new wind resources are not cost effective additions for PacifiCorp even if a PTC is assumed to be renewed into the future. Basing the prices paid to QFs on an inflated price of already uneconomic wind resources by removing the PTC would be inappropriate.

Q. Do you agree with OneEnergy's proposal to adjust the renewable avoided costs for the existence of the PTC along with other regular avoided cost updates in the future?

A. No. OneEnergy's proposal is not practical. The renewable resource deficiency period is many years in the future while the PTC has typically only been extended for short periods of time. At the time of the annual updates there will likely not be any additional information regarding PTCs when the avoidable renewable resource is scheduled to come online.

Q. Does this conclude your reply testimony on Issue 4?

A. Yes. Company witness Mr. Griswold will provide reply testimony regarding Issue 4B.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/301
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

April 2013

Comparison of Avoided Costs Using Mid C vs. Blended Market
$/MWh

Year	Total Avoided Costs (1)		
	Market Blend Filing Filed March 21, 2012	Mid-C Market Filing Filed March 2, 2012	Difference
	(a)	(b)	(c) (a) - (b)
2012	$27.56	$26.40	$1.16
2013	$32.46	$31.99	$0.47
2014	$35.58	$35.08	$0.50
2015	$37.89	$37.67	$0.22
2016	$50.86	$50.86	$0.00
2017	$53.41	$53.41	$0.00
2018	$56.66	$56.66	$0.00
2019	$59.77	$59.77	$0.00
2020	$59.15	$59.15	$0.00
2021	$61.78	$61.78	$0.00
2022	$66.01	$66.01	$0.00
2023	$68.31	$68.31	$0.00
2024	$67.80	$67.80	$0.00
2025	$69.68	$69.68	$0.00
2026	$72.41	$72.41	$0.00
2027	$74.89	$74.89	$0.00
2028	$76.88	$76.88	$0.00
2029	$78.59	$78.59	$0.00
2030	$79.63	$79.63	$0.00
2031	$80.89	$80.89	$0.00
20 Year (2012 - 2031) levelized Price at 7.17% Discount Rate			
$/MWh	$54.28	$54.08	$0.20

Note: (1) Total Avoided Costs with Capacity Costs included at 85% Capacity Factor

Docket No. UM-1610
Exhibit PAC/400
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Bruce W. Griswold

April 2013

Q. Are you the same Bruce W. Griswold who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (the Company)?

A. Yes.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony today is to respond to parties' direct testimony on Issues 1B, 1D, 2B, 2C, 4B, 5A, 5B, 5C, 5D, 6B and 6I listed in Appendix A – Issues list to Chief Administrative Law Judge Michael Grant's December 21, 2012 Ruling. I will be responding to the proposals and analysis presented by Mr. Adam Bless on behalf of Public Utility Commission of Oregon (Commission) Staff (Staff); Messrs. Don Schoenbeck, Jeremiah Camarata, and Edson Pugh on behalf of Renewable Energy Coalition (REC); Mr. William Eddie on behalf of OneEnergy, Inc. (OneEnergy); Messrs. Philip Carver and Tom Elliot and Ms. Kacia Brockman on behalf of the Oregon Department of Energy (ODOE); Messrs. Ormand Hilderbrand, Don Reading, and Tom Svendsen on behalf of the Community Renewable Energy Association (CREA); Mr. John Harvey on behalf of Threemile Canyon Wind I, LLC (Threemile Canyon); Mr. Greg Price on behalf of the Small Business Utility Advocates (SBUA); and Mr. Jimmy Lindsay on behalf of Renewable Northwest Project (RNP).

Q. How is your testimony organized?

A. My testimony is organized consistent with the list of issues identified for Phase I and presented in my direct testimony.

Q. Please summarize your testimony.

A. My testimony reaffirms or clarifies the Company's recommendations made in my direct testimony for the Phase I issues list and rebuts arguments made by parties. I also include testimony regarding factual allegations made by Threemile Canyon specific to its complaint against the Company in Docket No. UM 1546, which is currently stayed.[1]

- Issue 1B: Levelization of avoided cost prices is not a requirement for projects to secure financing and parties have not quantified or justified the shift in risk to utility customers.
- Issue 1D: Eliminate the unused avoided cost pricing options from Schedule 37—Gas Market Indexed and Banded Gas Market Indexed.
- Issue 2B: The Company is working with other parties in the docket to address certain greenhouse gas offsets, specifically those 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, which may be appropriately excluded from the definition of a renewable energy certificate.
- Issue 2C: Subject to final contract language, the Company recognizes that the standard contract can be written to be consistent with Order No. 11-505 and will be the governing document on ownership of non-energy attributes between the utility and the qualifying facility (QF).

[1] On March 29, 2013, the Company filed a Motion to Strike (Motion) certain portions of Threemile Canyon witness John A. Harvey's testimony on that basis that Mr. Harvey's testimony circumvented the Commission's order to stay proceedings in Docket No. UM 1546. As of the time of filing this reply testimony, a ruling has not been issued on the Motion. In the event the Company prevails on the Motion, it will withdraw portions of testimony that relate specifically to Docket No. UM 1546.

- Issue 4B: Third-party transmission service costs and savings associated with load pocket constraints should be the responsibility of the QF and can be accomplished by an addendum to the power purchase agreement (PPA) or alternatively, as a stand-alone agreement between the QF and the Company.
- Issue 5A: The Company's proposed 3 MW eligibility threshold for Schedule 37 avoided cost prices and PPAs is the cleanest and most transparent threshold which allows small and community based renewable projects access to the standard contracts and avoided cost prices.
- Issue 5B: The Company is working with parties in the docket on a revised version of the Partial Stipulation that will clarify the requirements of a "single QF" that would address concerns raised in direct testimony with respect to disaggregation of QF projects.
- Issue 5C: Wind and photovoltaic (PV) solar are the two resource types that have the ability to disaggregate from a single QF project to multiple smaller QF projects that can qualify for Schedule 37 prices and contract terms.
- Issue 5D: Renewable energy credit ownership is defined by Order No. 11-505 when the QF selects renewable avoided cost prices.
- Issue 6B: A legally enforceable obligation should be established when the QF and the Company agree on final draft PPA.
- Issue 6E: The mechanical availability guarantee should be increased to 90 percent in contract year three and allowed scheduled maintenance hours reduced to 60 hours per wind turbine per year, based on demonstrated performance to date and industry standards.

- Issue 6I: The fixed price portion of the QF PPA term should be reduced to 10 years, which still provides a sufficient term to secure financing.

<u>Issue 1: Avoided Cost Price Calculation</u>

Issue 1B: Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended that QFs should not have the option to elect levelization of avoided cost prices over the term of a QF PPA. If levelization is an option, additional credit and security requirements would be necessary to cover the associated front-loaded cost and risk.

Q. Has your recommendation changed?

A. No.

Q. Staff concludes that QFs should not have the option to elect avoided cost prices that are levelized or partially levelized.[2] Do you agree with Staff's conclusion?

A. Yes. Staff's position is that the Commission considered and decided against proposals for levelized pricing in Docket No. UM 1129. PacifiCorp agrees with Staff that there are no changes in the arguments and circumstances presented in UM 1129 that warrant a change in the Commission's policy against levelized prices.

[2] Staff/100, Bless/12.

Q. REC proposes that QFs should have the option to select levelized pricing in certain circumstances. Do you agree?

A. No. REC's testimony on this topic seems to suggest that the "certain circumstances" are limited.[3] However, REC's suggestion appears to be that a levelization option should be offered to existing QFs when seeking a PPA renewal. Far from limited, if that suggestion is applied to PacifiCorp at the current time, the Company and its customers could be exposed to levelization risk associated with over 51 QFs when PPA renewals are sought. REC does not provide an explanation as to why this significant shift in risk from QFs to utility customers is necessary or reasonable. This proposal should therefore be rejected.

Q. OneEnergy proposes that distributed generation QFs 3 MW and smaller that are directly interconnected to the purchasing utility's distribution system have the option of electing levelized pricing.[4] Do you agree with OneEnergy's assessment and conclusions regarding this exception?

A. No. Although OneEnergy's proposal is framed as an exception to the Commission's policy against levelized pricing, the exception for 3 MW and smaller projects would allow so many QFs to elect levelized pricing that it is not really an exception. Based on the Company's historical QF agreements, providing a levelized pricing option to those at or under a 3 MW threshold would have meant offering levelized prices to half of the Oregon QF projects with which the Company has executed PPAs. Regardless of the size of the QF project, the Company and its customers are still accepting credit risk associated with the risk

[3] Coalition/100, Lowe/22.
[4] OneEnergy/100, Eddie/39.

of default by the QF project in the early years. I suggest that this is not an appropriate balance of risk between QFs and utility customers.

Q. CREA argues that QFs should have the option to elect levelized pricing because non-levelized rates can present a problem for financing a QF project.[5] Do agree with CREA's assessment and conclusion?

A. No. CREA presents Idaho as the primary example of levelized avoided cost pricing being an accepted option. However, the Company has 20 active QF PPAs in Idaho and all successfully developed and financed their QF projects on a non-levelized price basis. The Company's experience has been that most QF developers that seek standard agreements are seeking a fixed price contract to secure financing and not levelized avoided cost prices.

Issue 1D: Should the Commission eliminate unused pricing options?

Q. Please summarize the recommendation made in your direct testimony.

A. I proposed to eliminate the Gas Market Indexed and Banded Gas Market Indexed avoided cost pricing options from Schedule 37, which sets forth the Company's standard avoided costs.

Q. Has your recommendation changed?

A. No.

Q. Do any other parties support PacifiCorp's proposal?

A. Yes. Staff recommends that the unused variable market-based options complicate the avoided cost price schedules and therefore the Commission should eliminate them.[6] Similarly, CREA sees no reason to object to PacifiCorp's proposal.

[5] CREA/200, Reading/9-12.
[6] Staff/100, Bless/14.

However, CREA proposes that the Commission require utilities to make these currently-unused price options available upon request.[7]

Q. Does PacifiCorp agree with CREA's proposal?

A. No. Schedule 37 should be transparent and self-explanatory. The purpose of Schedule 37 is to provide a publicly available document that details the requirements and options for the standard QF. Having the Company keep these pricing options available upon request, even if not posted in Schedule 37, is contrary this purpose.

Q. Does this conclude your testimony on Issue 1?

A. Yes. Company witness Mr. Brian S. Dickman will provide reply testimony regarding Issues 1A and 1C.

Issue 2: Renewable Avoided Cost Price Calculation

Issue 2B: How should environmental attributes be defined for purposes of Public Utility Regulatory Policies Act (PURPA) transactions?

Q. Please summarize the recommendation made in your direct testimony.

A. I concluded that environmental attributes should be defined consistent with the ODOE promulgated rules, codified at OAR 330-160-0015(13) that defines Renewable Energy Certificate.

Q. Has your recommendation changed?

A. No. However, the Company has engaged with other parties to this docket to explore the possibility that certain greenhouse gas offsets, specifically those associated with methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the

[7] CREA/200, Reading/14.

generation of electricity, may be appropriately excluded from the definition of Renewable Energy Certificate codified in OAR 33-160-0015(13). Discussions with parties regarding the potential resolution of this issue are ongoing.

Q. OneEnergy raises a concern that Energy Trust of Oregon (ETO) will not support a project if the project's renewable energy certificates may be sold off by the utility to third parties for other RPS obligations in other states, or to voluntary buyers.[8] What is your response to OneEnergy's concern?

A. OneEnergy's concerns can be addressed via agreements between the Company and ETO. In exchange for project funding from ETO, some or all of the renewable energy certificates produced by the QF are transferred to ETO and are then transferred to Oregon customers through the Company's account with the Western Renewable Energy Generation Information System (WREGIS). The Company then is required under Oregon law to retire renewable energy certificates on behalf of and for the benefit of PacifiCorp's Oregon customers. To document this transfer process, PacifiCorp is executing a new master renewable energy certificate transfer agreement with ETO to manage the control and transfer of renewable energy certificates with the individual ETO funded projects.

Issue 2C: Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended that the Commission amend OAR 860-022-0075 to be consistent

[88] OneEnergy/100, Eddie/20-21.

with Order No. 11-505 and state that the utility receives the non-energy attributes during periods of renewable resource deficiency.

Q. Has your recommendation changed?

A. Yes. The Company continues to believe that amending the OAR would be the most effective mechanism to establish ownership of renewable energy certificates to be consistent Order No. 11-505 and provides a clear point for public and regulatory reference. However, based on comments by Staff, ODOE and CREA, the Company recognizes that the standard QF contract can be written to be consistent with Order No. 11-505 and will be the governing document on ownership between the utility and the QF. Therefore, subject to adequate language being incorporated into the standard QF contract, the Company would agree that this would be an acceptable alternative solution for this issue.

Q. REC argues that non-energy attributes, which may include other rights and benefits that are different from compliance with a state renewable portfolio standard, should remain with the QF.[9] Do you agree?

A. No. The very definition of renewable energy certificate as established by ODOE in OAR 330-160-0015 for the Oregon renewable portfolio standard and as defined in the WREGIS Operating Rules, establishes that the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources are transferred as a unit and cannot be disaggregated. WREGIS further goes on to define a WREGIS Certificate:

> A WREGIS Certificate represents all Renewable and Environmental Attributes from one MWh of electricity generation from a renewable energy Generating Unit registered with WREGIS or a Certificate imported

[9] Coalition/100, Lowe/24.

> from a Compatible Registry and Tracking System and converted to a WREGIS Certificate. The WREGIS system will create exactly one Certificate per MWh of generation that occurs from a registered Generating Unit or that is imported from a Compatible Registry and Tracking System. Disaggregation of certificates is not currently allowed within WREGIS.[10]

Therefore, REC's recommendation should be rejected.

Q. Does this conclude your testimony on Issue 2?

A. Yes. Company witness Mr. Dickman will provide reply testimony regarding Issue 2A.

<u>Issue 4: Price Adjustments for Specific QF Characteristics</u>

Issue 4B: Should the costs or benefits associated with third-party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

Q. Please summarize the recommendation made in your direct testimony.

A. I proposed that individual QFs should be responsible for the any third-party transmission costs incurred, or benefits realized, by the utility, associated with the purchase of that QF's energy. Third-party transmission costs and benefits should not be incorporated into the calculation of the standard avoided cost price. Rather, the costs or benefits associated with third-party transmission should be allocated in the contract with the QF as an addendum to the PPA.

Q. Has your recommendation changed?

A. No.

[10] WREGIS Operating Rules are available online at: http://www.wecc.biz/WREGIS/Pages/default.aspx.

Q. Staff finds that responsibility for the incremental costs to move QF generation out of a load pocket lies with the QF.[11] Do you agree?

A. Yes. The Company has systematically incurred substantial third-party transmission costs as the result of moving QF generation out of load-constrained areas that are not offset by avoided third-party transmission costs. The cost of third-party transmission is more appropriately borne by the QF, not PacifiCorp customers.

Q. Staff's proposal is based on characterizing third-party transmission costs as "interconnection costs" as defined in 18 C.F.R. 292.101(7). Is this characterization appropriate?

A. In part. Staff raises the possibility that third-party transmission costs may be considered "interconnection costs" under 18 C.F.R. 292.101(7). According to this definition, "interconnection costs" includes reasonable transmission costs "to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources."[12] In general, as explained in more detail in Company witness Mr. Nathan R. Ortega's testimony, the Company considers interconnection costs and transmission costs to

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[11] Staff/100, Bless/30.
[12] 18 C. F. R. 292.101(7) states in full: "*Interconnection costs* means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs."

be related to two discrete services. Interconnection costs are related to the physical requirements of interconnection while transmission costs are related to power delivery. However, for purposes of determining whether or not the QF should bear the costs of any third-party transmission requirements, the language in 18 C.F.R. 292.101(7), as well as the Commission's administrative rules regarding interconnection costs, are instructive. Third-party transmission costs are in excess of the costs the Company would normally incur and are therefore not consistent with the indifference standard. As I explain later in my testimony, the Company would not opt to acquire or build generation in a load-constrained area where the Company would need to purchase third-party transmission to move the generation out of a load pocket. However, this is exactly what the QF is requiring the Company to do, thereby increasing the cost to customers. Therefore, for purposes of allocating cost responsibility, third-party transmission costs are analogous to interconnection costs and should similarly be borne by the QF.

Q. REC proposes that the Commission reaffirm its policy that there should be no adjustments to standard contracts and pricing. Do you agree?

A. As explained in detail in Company witness Mr. Dickman's testimony, the Company agrees that adjustments to standard contracts and pricing should be limited, if not eliminated. The Company is not proposing that the incremental transmission costs to move QF generation out of a load pocket be incorporated into or considered an adjustment to the avoided cost prices nor to modify the standard contract terms. Rather, similar to interconnection costs, these are costs incurred directly by the utility and are recovered outside of the avoided cost rate.

The Commission requires QFs to pay for these costs to prevent customer subsidization of QFs and ensure that customers remain indifferent to QF purchases. I have recommended that payment for the third-party transmission costs can be accomplished by an addendum to the PPA or alternatively, as a stand-alone agreement between the QF and the Company.

Q. Is the Company's proposal symmetrical if a QF allows the Company to avoid third-party transmission costs?

A. Yes. The Company's proposal is equitable because the Company proposes not only to charge QFs for costs incurred, but also to credit savings to QFs when they allow PacifiCorp to save third-party transmission expenses. PacifiCorp made this symmetrical approach explicit in its revised version of Schedule 37 filed in Docket No. UE 235.

Q. Threemile Canyon argues that PURPA, and FERC's regulations implementing PURPA, do not permit a host utility to assess transmission charges to a QF that is selling its output to the host utility.[13] Do you agree?

A. No. As an initial matter, because Threemile Canyon's arguments are primarily legal arguments, the Company will more fully address them in legal briefs. My testimony therefore includes only a brief summary of why Threemile Canyon's analysis is not directly applicable to the question at issue in this docket. Threemile Canyon reliance on 18 CFR 292.303(d) and the case of *Entergy Services, Inc.* are not applicable to a circumstance where a utility must purchase third-party transmission to move output to load for a directly interconnected QF. Neither the regulation nor *Entergy Services, Inc.* addresses the issue of whether the QF is

[13] Threemile/100, Harvey/20.

responsible for incremental third-party transmission costs. It is my understanding that 18 CFR 292.303(d) and the *Entergy* case stand for the proposition that the utility is obligated to purchase QF output and deliver it to load. The Company does not dispute this obligation. Rather, the Company does not interpret this obligation as requiring it to incur costs above its avoided cost as a result of purchasing third-party transmission. 18 CFR 292.303(d) and the *Entergy* case simply do not address how the cost of third-party transmission should be allocated.

Q. Threemile Canyon also claims PacifiCorp's proposal to assign third-party transmission costs to QFs is discriminatory, in violation of PURPA. Can you please explain this argument?

A. Yes. Threemile Canyon argues that if the electric utility is charging its retail and/or wholesale customers for third-party transmission costs of transmitting electricity to them from non-QF generation, especially including those which are company owned renewable generators of the identical generation technology (i.e., wind power), the utility cannot discriminate against QFs by failing to pay for third-party transmission for the QF.[14] The fact that the Company pays third-party transmission costs in other situations, a fact which the Company does not dispute, does not mean the Company's proposal to assign third-party transmission costs to QFs results in discrimination against QFs, particularly given the unique policy goals of PURPA. Again, the appropriate cost allocation for third-party transmission costs are analogous to the cost allocation for interconnection costs. The Company pays the interconnection costs for Company-owned projects; it

[14] Threemile/100, Harvey/30.

does not pay interconnection costs for third-party owned projects, QF or otherwise. Threemile Canyon's argument that this is discriminatory against QFs is simply unavailing.

PURPA's important policy of maintaining customer indifference to utility purchases of QF output supports the Company's proposal.[15] If utilities are required to pay third-party transmission costs, they are effectively paying more than avoided costs for QF output. Threemile Canyon's argument that the Company's proposal discriminates against QFs again ignores the fact that the Company would not intentionally acquire or build generation in a location where the Company would have to bear third-party costs to transmit generation out of a load-constrained area. Under the mandatory purchase obligations of PURPA, the Company must purchase QF output regardless of where it is located. Requiring QFs to pay for the additional third-party transmission costs associated with transmitting QF output out of load-constrained areas acknowledges and accounts for the different circumstances regarding third-party transmission costs vis-à-vis QF and non-QF generators.

Q. Threemile Canyon also introduces a series of factual allegations in its testimony that relate to its complaint against PacifiCorp, currently stayed in Docket No. UM 1546. How do you respond to these factual allegations?

A. I will respond to Threemile Canyon's complaint-specific factual issues at the end of my testimony. As indicated earlier, the Company filed a Motion to Strike portions of Threemile Canyon's direct testimony as it relates to these stayed proceedings. A response to the Motion to Strike is pending. In the event the

[15] *So. Cal. Ed. Co.*, 71 F.E.R.C. ¶ 61,269, 62,080 (1995).

Motion to Strike is granted, I will withdraw my testimony as it relates to docket UM 1546.

Q. Does this conclude your testimony on Issue 4?

A. Yes. Company witness Mr. Dickman will provide reply testimony regarding Issues 4A and 4C.

Issue 5: Eligibility Issues

Issue 5A: Should the Commission change the 10 MW cap for the standard contract?

Q. Please summarize the recommendation made in your direct testimony.

A. I proposed reducing the eligibility cap for standard avoided cost prices and contracts to a nameplate capacity rating of 3 MW. Projects over 3 MW would be eligible for non-standard avoided cost prices and contracts.

Q. Has your recommendation changed?

A. No.

Q. Staff recommends keeping the eligibility cap at 10 MW, predicated on modifications it proposes to the standard and renewable method of calculating avoided costs. Do you agree?

A. No. The 3 MW threshold proposed by the Company is a very clear line that will continue to provide standard avoided cost prices and contract terms to the small community based renewable projects. The Company believes that multiple modifications to the standard avoided cost calculation will increase the administrative costs and complexity of updating and validating the standard avoided cost prices. In addition, Staff agrees with the Company's proposed a 3 MW threshold if Staff's proposed modifications are not implemented.[16]

Q. A number of parties argue that the eligibility cap should not be lowered because it is more difficult for QFs to negotiate contracts over 10 MW than fewer than 10 MW. Do you agree with this?

A. No. The Company's experience is that regardless of the standard contract threshold, QF projects over 3 MW generally have technical, business, and legal experts engaged in the analysis, development, and contracting phases of their project regardless of the resource technology type. With the rapid advance of new generation technologies, even a "small" project less than 3 MW may have experts involved in design and development, ultimately leading to their involvement in the actual QF PPA process on contract terms such as project milestones, generation profiles, performance measures, etc.

Q. A number of parties also claim that utilities' concerns could be addressed in ways other than lowering the size of the threshold for all QFs. How do you respond to this?

A. The 3 MW threshold is a very clean and understood measure. It is simple and provides the QF with a known requirement that they can take into consideration as they design their project. Some parties have proposed a number of changes to standard avoided cost methodologies. While these changes can accomplish the goal of more accurate avoided cost prices, they are also more complicated, administratively burdensome, and could lead to disagreement and disputes.

[16] Staff/100, Bless/37.

Q. Will lowering the eligibility cap stop the development of community renewable energy in Oregon, as suggested by CREA?

A. No. CREA expressed concerns that lowering the eligibility cap would impede development of community-based renewable energy.[17] However, if you look at the QF development in Oregon with the Company, many of the QF projects at or under 3 MW that have been executed PPAs can be categorized as individuals or community-based renewable energy.

Q. Is it possible to address disaggregation concerns through a broad-based regulatory approach as opposed to a bright-line eligibility cap?

A. No. While, RNP suggests that a thoughtful regulatory approach could distinguish single projects from aggregated projects,[18] it is clear from the past that the Partial Stipulation developed in Docket No. UM 1129 did not prevent the disaggregation of a large project into multiple small projects. The Company believes that no matter how rigorous the approach is made, there are QF developers who will attempt to circumvent the process. A threshold of 3 MW provides the individual smaller project with a clear path to develop their project and reduces the ability to seek loopholes in the rules by the developer for a large single project.

Issue 5B: What should be the criteria to determine whether a QF is a "single QF" for purposes of the eligibility for the standard contract?

Q. Please summarize the recommendation made in your direct testimony.

A. I proposed that the passive investor exemption be removed from the Partial

[17] CREA/200, Reading/30.
[18] RNP/100, Lindsay/6.

Stipulation adopted in Docket No. UM 1129, with a waiver available to individual family or community-owned renewable projects.

Q. Has your recommendation changed?

A. No. However, the Company is working with parties to develop a revised version of the Partial Stipulation that may address some of the Company's concerns. These efforts are ongoing.

Q. OneEnergy supports a proposal that will allow only independent family or community-based projects to have common passive investors but disagrees with the proposal to prohibit shared infrastructure among QFs seeking a standard contract on the basis that shared infrastructure does not itself prove disaggregation.[19] Do you agree?

A. Yes, I agree in part. For clarity, I did not intend to imply in my direct testimony that QF projects cannot share infrastructure and common interconnection or that the Company is proposing a change to that component; such sharing is allowed under PURPA. As mentioned in response to the previous question, the Company is working with parties to develop a revised version of the Partial Stipulation that may resolve some of the Company's and other parties' concerns.

Q. RNP argues that the goal of single project criteria in the PURPA context should be to reveal economic interdependence and that the most important characteristics will be financial in nature.[20] Do you agree?

A. Yes, I agree in part. While economic interdependence is one of the primary issues evaluated through the Partial Stipulation, there are other criteria such as distance,

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[19] OneEnergy/100, Eddie/3.
[20] RNP/100, Lindsay/6.

common operation, and management that are important considerations when looking at disaggregation.

Q. OneEnergy also proposes that the nameplate capacity means AC output in the case of PV solar projects.[21] **Is this an acceptable proposal?**

A. Yes. It is important to keep consistency across the units in the standard agreements. While PV solar is generally described in DC wattage, the output and performance is measured in AC, thus the nameplate capacity should reflect and be consistent with the solar plant output.

Issue 5C: Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended that wind and photovoltaic (PV) solar are the two resource types capable of disaggregating from a large single project into multiple projects eligible for standard avoided cost prices and contract terms.

Q. Has your recommendation changed?

A. No. The Company's experience with QF developers for both wind and solar projects has demonstrated the capability of disaggregating a large project into multiple small projects.

Issue 5D: Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

Q. Please summarize the recommendation made in your direct testimony.

A. I proposed that Order No. 11-505 establishes renewable energy certificate ownership when receiving Oregon's renewable avoided cost prices. During the

[21] OneEnergy/100, Eddie/9.

resource sufficiency period, the QF assumes all ownership risk of the renewable energy certificates including registration of the QF facility with any appropriate agency or program, the qualification and application of those renewable energy certificates for any mandatory renewable portfolio standard (RPS) or voluntary renewable program, management or accounting of those renewable energy certificates, and the sales of those renewable energy certificates to third parties.

Q. Has your recommendation changed?

A. No.

Q. Does this conclude your reply testimony on Issue 5?

A. Yes.

<u>Issue 6: Contracting Issues</u>

Issue 6B: When is there a legally enforceable obligation?

Q. Please summarize the recommendation made in your direct testimony.

A. I explained that the issue of a legally enforceable obligation (LEO) involves many legal questions and proposed that the Commission set criteria for establishing a legally enforceable obligation using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37.

Q. Has your recommendation changed?

A. No.

Q. What do parties recommend with regard to creation of a LEO?

A. REC proposes that a LEO may be created once a QF has provided all the required information to the utility and after the utility has provided a draft PPA.[22] CREA argues that the Company's proposal overlooks a disagreement prior to reaching a

[22] Coalition/100, Lowe/18.

final draft contract could frustrate a QF's right to obligate itself to sell power and lock in rates.[23] Threemile Canyon argues that PURPA requires the Commission to place full control of creating a LEO with the QF.[24]

Q. Do you agree with the positions of these parties?

A. No. While all parties propose a change in the current methodology for determining when an LEO has been created, no party has presented evidence of abuse warranting such a change. Threemile Canyon's proposal in particular goes too far; under Threemile Canyon's proposal, a QF could download and print the standard QF PPA from the Company's website, sign it and thus create an LEO because it has simply signed a document without even communicating with the Company or going through the Schedule 37 or 38 contracting process. Further, Threemile Canyon's primary example of why creating a LEO must be solely controlled by the QF amounts to mischaracterization of the timing issues between the Company and Threemile Canyon and suggests a problem that does not exist: that utilities in general and PacifiCorp in particular are inappropriately delaying entering into standard contracts with QFs. Threemile Canyon accuses the Company of intentionally delaying executing a standard contract and points to the purported delay as a demonstration of "the need to keep the commitment (i.e., LEO creation) process in a QF's possession."[25]

In contrast to the specious claim of Threemile Canyon, the Company has not "steadfastly refused" to execute a standard contract with Threemile Canyon out of a desire to avoid the mandatory purchase obligations of PURPA. The

[23] CREA/100, Hilderbrand/18.
[24] Threemile/100, Harvey/36.
[25] Threemile/100, Harvey/37.

Company has sought to have the underlying policy issues surrounding assignment of third-party transmission costs resolved prior to entering into a standard contract with Threemile Canyon—a process that Threemile Canyon itself did not object to.[26] The Company has actively and in good faith participated in these proceedings and is committed to timely resolution of the general policy issues in this proceeding that have a direct impact on the underlying dispute stayed in UM 1546.

Although Threemile Canyon attempts to portray PacifiCorp as a bad actor, intentionally delaying execution of a standard contract, Threemile Canyon has not proven the existence of inappropriate delay tactics by PacifiCorp or any other electric utility that would require a change in how the timing of the creation of a legally enforceable obligation is determined.

Similarly, CREA's concerns regarding a frustration of a QF's right to obligate itself to sell power and lock in rates lacks merit. CREA overlooks the fact that the Company's Schedule 37 already provides for a Commission-based dispute resolution process.

[26] *See* Docket UM 1546, Ruling of Administrative Law Judge Wallace (Oct. 6, 2011). Threemile Canyon did not object to the Company's request to stay Threemile Canyon's complaint against the Company in UM 1546, pending resolution of UE 235, which was subsequently subsumed into UM 1610.

Q. CREA also suggests that the Commission implement a dispute resolution process similar to that of the Federal Energy Regulatory Commission (FERC) whereby a disputing party may file an unexecuted agreement and request that FERC resolve disputed terms.[27] What is your reaction to this approach?

A. I disagree with that approach. The Commission has already established a dispute resolution process for QFs in both Schedule 37 and Schedule 38. CREA fails to identify reasons why the Commission's dispute resolution process is insufficient or unsatisfactory.

Q. CREA also proposes that the Commission explicitly require utilities to inform QFs at the time of first contact of the next likely time that avoided costs will change.[28] Is this reasonable?

A. No. It is highly burdensome and may not be accurate based on when the QF makes first contact. In many cases, the Company receives a phone call requesting information on QF and the appropriate avoided cost schedule with little detail on timing, etc. Under the proposed options presented by the Company for avoided cost pricing updates, the timing and content of updates would be clearly known in advance; the need to inform QFs of potential avoided cost price changes at first contact would not be necessary.

Issue 6E: How should contracts address mechanical availability?

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended the Company increase the guaranteed availability in the

[27] CREA/100, Hilderbrand/18-19.
[28] *Id*. at 18.

Company's QF PPA to 90 percent beginning in contract year three through the remaining term of the PPA. I also propose that the Company reduce allowed scheduled maintenance to 60 hours per wind turbine per year.

Q. Has your recommendation changed?

A. No.

Q. Staff recommends that 200 hours of scheduled maintenance per turbine, per year, is a reasonable parameter that does not count against overall mechanical availability.[29] Do you agree?

A. No. A review of industry standards as well as actual operating data of wind QF PPAs was the basis for the Company's proposed scheduled maintenance hours.

Q. Staff further recommends that contract termination is too severe a penalty for failure to meet the MAG. Do you agree?

A. No. Contract termination as a result of a default under the PPA for non-performance should be allowed if there is a pattern of non-performance.

Q. Threemile Canyon argues that the need for mechanical availability provisions in QF contracts is out-of-date and contracts should not address mechanical availability.[30] Do you agree?

A. No. The purpose of mechanical availability is to ensure there is a performance measure for intermittent resources such that the wind turbine will generate when the wind is blowing. This standard is used by the Company in its QF and non-QF agreements with wind farms and also used by many utilities across the country. It is far less punitive than requiring some form of minimum delivery obligation.

[29] Staff/100, Bless/44.
[30] Threemile/100, Harvey/38.

Q. Threemile Canyon goes on to propose to use the concept of Wind Energy Capture instead of a MAG. What is your reaction to this proposal?

A. Wind Energy Capture appears to be a performance measure used by Threemile Canyon's parent company Exelon Power for rewarding employees as part of their annual incentive compensation program. Threemile Canyon's testimony clearly states that Exelon Wind utilizes mechanical availability as a performance measure for its entire wind fleet, in fact Exelon Power, in providing operations management, delivers documentation of the calculation of mechanical availability in all of their wind QF PPAs with the Company. Therefore, I disagree the argument that the MAG is out of date because Exelon's agreements with the Company are measured on it. A QF can certainly take advantage of implementing such a concept like Wind Energy Capture at its wind farm for the purpose of employee incentive compensation but PacifiCorp is seeking to ensure the performance of the wind farm for meeting load obligation, not the financial health of the wind farm employees.

Q. SBUA argues that it would be reasonable that for a higher MAG additional value is offered within the PPA, either in the form of higher rates paid for power produced or more amenable terms for the renewable energy generator.[31] Do you agree?

A. No. The MAG is a performance measure set to ensure delivery of power to the utility for serving load that is attainable based on industry standards.

Issue 6I: What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

[31] SBUA/100, Price/6-7.

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended that the current term length of up to 20 years be continued with the fixed price period in the contract changed from the initial 15 years to the initial 10 years. The remaining years of the PPA would be at the Electric Market Option.

Q. Has your recommendation changed?

A. No.

Q. Staff recommends retaining the current policy of 20 year maximum contract with the fixed price option in effect for at most 15 years.[32] What is your response to this proposal?

A. As discussed in my direct testimony, the Company does not believe the QF is disadvantaged by a shorter fixed rate portion of the contract based on the terms selected in the QF PPAs executed by the Company since Order No. 05-084. The Company executed multiple new QF PPAs with parties that had terms less than 10 years.

Q. REC similarly argues that the current policy should be maintained, on the basis that longer term agreements are needed to meet financing and long-term planning needs.[33] How do you respond?

A. Again, as discussed in my direct testimony the Company does not believe the QF is disadvantaged by a shorter fixed rate portion of the contract based on the terms selected in the QF PPAs executed by the Company since Order No. 05-084.

[32] Staff/100, Bless/40.
[33] Coalition/100, Lowe/20.

Q. REC also questions the Company's statement that a large percentage of new QFs elected terms of 15 years or less.[34] How do you respond?

A. My testimony is supported by data from actual PPAs executed with QFs.

Q. OneEnergy proposes that distributed generation (DG) QFs be allowed to sign fixed-price contracts up to 25 years in length to make it possible for DG projects to obtain financing.[35] Do you agree with OneEnergy's conclusion?

A. No. There is no evidence that a DG QF requires additional fixed price years to be viable. The Company has multiple QFs where the generation is an integral part of a customer site and operation. None of those resources required a PPA beyond the 15-year fixed rate term and several constructed projects under term lengths of less than 15-years.

Q. CREA asserts that the current term of 15 years with fixed rate is the absolute minimum that can be financed by a 10 MW project and that it would be reasonable for the Commission to extend the fixed rate term to 20 years.[36] Do you agree?

A. No. Since the implementation of the 20-year PPA with a 15-year fixed rate portion, the Company has executed multiple QF PPAs with various resource types. None of those projects had concerns with the 15-year term and several executed agreements at less than 15 years, thus supporting the Company's proposed reduction in the fixed rate portion of the contract. Extending the fixed portion to 20-years simply shifts more price risk to retail customers.

[34] Coalition/200, Schoenbeck.
[35] OneEnergy/100, Eddie/38.
[36] CREA/200, Reading/35.

Q. Does this conclude your testimony on Issue 6?

A. Yes. The remainder of Issue 6 will be addressed in Phase II of this docket.

Company Response to Threemile Canyon Wind Complaint

Q. Please summarize this portion of your testimony.

A. This portion of my testimony will address factual allegations made by Threemile Canyon specific to its complaint against the Company, currently stayed in Docket No. UM 1546. Company witness Mr. Ortega will also provide the Company's response to these allegations from the Company's transmission function, with respect to Threemile Canyon's claim that errors were made as part of the interconnection process.

Q Please describe the Threemile Canyon wind QF project.

A. Threemile Canyon operates a 9.9 MW wind QF directly interconnected to the Company's system on the 34.5 kV Simtag Feeder out of the Dalreed substation near Arlington, Oregon. The Dalreed substation and the Company's associated transmission and distribution facilities serve isolated load, which is connected to the rest of the Company's system only by transmission facilities owned by the Bonneville Power Administration (BPA). The Company load served from the Dalreed substation fluctuates from a high of 40 MW to a low of 2 MW. Prior to the interconnection and operation of the Threemile Canyon QF, there was no load-serving generation in the Dalreed area and the Company imported all of the power it needed to serve the Dalreed load by means of third-party transmission provided by BPA. With the addition of the Threemile Canyon QF, generation at Dalreed will at times exceed load by up to 7.9 MW under normal load conditions (an "Excess Generation Event" resulting from "Excess Generation"). To ensure that Threemile Canyon QF output can be used during Excess Generation Events, The Company must purchase a minimum of 8 MW of firm point-to-point transmission from BPA to move the excess Threemile Canyon generation from Dalreed to another location on the Company's system where there is sufficient load to absorb the Excess Generation. In order to move Threemile Canyon QF generation out of the Dalreed load pocket during Excess Generation Events, the Company has paid BPA for point-to-point transmission service (including required ancillary services) and associated transmission service application fees (collectively "BPA Transmission Services").

Q. What was the history of the QF PPA development with Threemile Canyon?

A. The Company was contacted by the developer of Threemile Canyon in 2005 and subsequently notified them of Excess Generation issues in 2006 in early discussions of their project. In late 2006, the developer indicated they were not proceeding with the project as proposed and communication ceased on the project. In December 2008, after its project was nearly completed, Threemile Canyon notified PacifiCorp's merchant function that they sought a 20-year PPA per Schedule 37. The Company again identified the potential for Excess Generation Events and the need for third-party transmission on December 19, 2008—the same day Threemile Canyon made its first request for a PPA for its current 9.9 MW project. The Company and Threemile Canyon attempted to negotiate the long-term agreement, which would include Threemile Canyon agreeing to pay for the BPA firm point-to-point transmission or agree that curtailment of Threemile Canyon output without payment could occur when such output will exceed Dalreed load. This was unsuccessful. Rather, the Company and Threemile Canyon agreed to disagree and since June 2009, the Company has purchased all net output from the Threemile Canyon QF at a point of delivery in the Dalreed load pocket under a short-term PPA. The short-term PPA is in the form of the Commission-approved standard agreement for intermittent resources with mechanical available guarantee. Pursuant to the short-term PPA, the Company has paid Threemile Canyon for all Threemile Canyon QF net output at the fixed avoided cost prices in Schedule 37 in effect June 2009. The Schedule 37 fixed avoided cost price was derived without regard to, and makes no allowance for, third-party transmission costs or third-party losses the Company must incur to make use of Excess Generation from the Threemile Canyon QF. Net output from the Threemile Canyon QF has at unpredictable times exceeded, and likely will continue to exceed unpredictably, all load served in the Dalreed load pocket by up to 7.9 MW.

Excess Generation Events have occurred in 2009, 2010, 2011 and 2012. Prior to purchasing net output from Threemile Canyon QF, the Company owned no generation resource within the Dalreed load pocket and controlled no transmission rights for moving power out of the Dalreed load pocket.

At present, the Company has expended over $200,000 on such BPA Transmission Services for Threemile Canyon. Prior to the Company paying for BPA Transmission Services in 2009, Threemile Canyon was aware that the Company acquired such BPA Transmission Services in order to provide transmission for the Threemile Canyon QF output during Excess Generation Events. The Company and Threemile Canyon agreed to disagree who must pay for BPA transmission necessary to move excess generation out of the Dalreed load pocket. The Company would not have incurred the costs of BPA Transmission Services if Threemile Canyon were not delivering to the Company's system at the Dalreed load pocket (or another Company load pocket). The Company merchant and Threemile Canyon have extended the short-term Schedule 37 PPA without interruptions multiple times while the Company has sought to have Threemile Canyon agree to pay for the firm point-to-point transmission or be curtailed. Threemile Canyon has not been willing to agree to these conditions. To date, the Company has paid all costs of third-party transmission to manage Excess Generation Events without contribution from Threemile Canyon.

On July 1, 2011, Threemile Canyon filed a complaint with the Oregon Commission alleging: (1) that it is eligible to sell its entire output net of station service to the Company in accordance with Schedule 37 without adjustments for incremental third-party transmission costs incurred by the Company when QF generation exceeds load in the Dalreed area; and (2) that the Company committed several errors in processing Threemile Canyon's interconnection and power purchase requests and that equitable considerations therefore dictate that the Company, rather than Threemile Canyon, should bear third-party transmission costs or other additional costs.

The Company contends that it committed no error by first identifying the potential for Excess Generation Events and third-party transmission on December 19, 2008—the same day Threemile Canyon made its first request for a PPA for its current 9.9 MW Facility. Further, the Company denies that Schedule 37 compels the result sought by Threemile Canyon. The Company takes the position that requiring it to pay full published avoided cost rates under Schedule 37 for Threemile Canyon's output and requiring the Company to pay for the third-party transmission necessary to move excess generation to adequate load violates PURPA by requiring a utility and its customers to pay more than full avoided cost for QF output.

As explained by Company witness Mr. Ortega, in the context of an interconnection request under Schedule 37, the Company transmission function was correct to conclude that it is the "Transmission Provider" and that there is no "Affected System." In the context of a Schedule 37 request for a power purchase agreement, the Company merchant timely and reasonably identified and notified Threemile Canyon of the potential for Excess Generation and third-party transmission issues. Moreover, the Company's merchant function worked diligently, cooperatively, and in good faith with Threemile Canyon to seek a mutually agreeable resolution to this matter that would include an addendum to the long-term PPA to clarify the transmission, curtailment, and other issues requested by Threemile Canyon. The Company merchant executed a standard PPA on a short-term basis, which the parties have extended multiple times, in order to allow Threemile Canyon to sell power from its facility at full published avoided cost rates while the parties attempted to resolve this matter. Any delay in resolving this matter has not been caused by the Company but by the inherent difficulty in finding a mutually agreeable resolution and to some degree by the delay in progress and negotiations created when Exelon Generation Company, LLC purchased 100 percent of the John Deere Renewables, LLC assets in August 2010 with the sale closing in December 2010.

As explained earlier in my testimony, equitable consideration and the public interest favor not requiring the Company, and ultimately the Company's customers, to pay both full published avoided cost rates and the cost of third-party transmission service made necessary by Threemile Canyon's decision to deliver Excess Generation to the Dalreed load pocket.

Q. Does this conclude your reply testimony?

A. Yes, it does.

Docket No. UM-1610
Exhibit PAC/500
Witness: Nathan R. Ortega

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Nathan R. Ortega

April 2013

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (the Company).

A. My name is Nathan R. Ortega. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am the Director of Transmission Services for PacifiCorp overseeing generation interconnections.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a Bachelor's Degree in Electrical Engineering from New Mexico State University with an emphasis in power engineering. My experience spans more than 12 years in the electric utility business and electric power industry in general. I have experience and management responsibility at PacifiCorp for Project Delivery, Substation Engineering, and most recently Transmission Services, overseeing generator interconnections.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses claims made by Threemile Canyon Wind I LLC (Threemile Canyon) in its complaint against PacifiCorp, currently stated in Docket No. UM 1546,[1] regarding alleged errors made during Threemile Canyon's interconnection process.

Q. Please summarize your testimony.

A. I will explain how Threemile Canyon's claims that the Company committed

[1] On March 29, 2013, the Company filed a Motion to Strike (Motion) certain portions of Threemile Canyon witness John A. Harvey's testimony on that basis that Mr. Harvey's testimony circumvented the Commission's order to stay proceedings in Docket No. UM 1546. As of the time of filing this reply testimony, a ruling has not been issued on the Motion. In the event the Company prevails on the Motion, it will withdraw this testimony which solely relates to Docket No. UM 1546.

errors during its interconnection process are baseless and misleading. Threemile Canyon mischaracterizes the term “Affected System” to conclude that PacifiCorp erred when it did not identify the Bonneville Power Administration (BPA) as a system affected by the proposed generator facility interconnection. In reaching this conclusion, Threemile Canyon conflates the provision of two distinct and separate services – interconnection service and transmission service. Affected Systems in the generator interconnection context are neighboring third-party transmission systems that face potential adverse impacts as a result of interconnecting a generating facility. Notably, the purpose is to identify *other transmissions systems* that may be physically affected by the interconnection; it is *not* to identify potential financial impacts to a generator associated with future financial arrangements for the delivery of its output. The potential need to make financial arrangements for transmission service from a third-party, in this case BPA, to move generation from a generating facility to load, is not considered as part of the generation interconnection process.

Q. Threemile Canyon cites to PacifiCorp’s Open Access Transmission Tariff (OATT) to conclude that the definition of “Affected System” is “an electric system other than the Transmission Provider’s Transmission System that may be affected by the proposed interconnection.” Do you agree that this is the correct definition of Affected System?

A. I agree that this is how Affected System is defined in PacifiCorp’s OATT and in Threemile Canyon’s Distribution Generator Interconnection Agreement (DGIA).

Q. Are there any other rules or regulations, other than PacifiCorp's OATT, that shed light on the definition of Affected System?

A. Yes. Because Threemile Canyon is a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the Oregon Small Generator Interconnection Rules apply to Threemile Canyon's interconnection, rather than PacifiCorp's OATT, which is under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The current Oregon Small Generator Interconnection Rules, found in Oregon Administrative Rules Chapter 360, Division 82, includes definitions that are helpful in interpreting the correct meaning of Affected System. OAR 860-082-0015(2) defines "Affected System" as a transmission or distribution system, not owned or operated by the interconnecting public utility, which may experience an adverse system impact from the interconnection of a small generator facility. Under OAR 860-082-0015(1), "Adverse system impact" means a negative effect caused by the interconnection of a small generator facility that may compromise the safety or reliability of a transmission or distribution system.

Q. Are the Oregon definitions of Affected System and Adverse System Impact consistent with your understanding of how these definitions are generally understood to apply in the generator interconnection context?

A. Yes.

Q. During Threemile Canyon's interconnection process, were any Affected Systems identified?

A. Affected Systems were not identified because there were no negative effects caused by the interconnection of Threemile Canyon's small generator facility that had the potential to compromise the safety or reliability of a transmission or distribution system.

Q. Why didn't the Company identify as part of the interconnection process the potential that third-party transmission arrangements would be necessary to move Threemile Canyon's output to PacifiCorp load?

A. Interconnection service is distinct from transmission service. The interconnection process does not identify how a generating facility will sell or deliver its output.

Q. Is it reasonable to assume that Threemile Canyon would have been aware of this distinction?

A. Yes. In section 1.3 of Threemile Canyon's DGIA it makes this clear by stating:

> this agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable entity.

The Interconnection Agreement is provided as Exhibit PAC/501.

Q. How and when should Threemile Canyon have been notified regarding the need for third-party transmission?

A. Threemile Canyon was notified by PacifiCorp's merchant function, which is responsible for making transmission arrangements for QFs, which are designated network resources under PacifiCorp's OATT. Company witness Mr. Bruce W. Griswold provides testimony that addresses when and how Threemile Canyon was notified of this issue.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/501
Witness: Nathan R. Ortega

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Nathan R. Ortega

April 2013

Print Form

Exhibit PAC/501
Ortega/1

Check-sheet for Handling of Transmission Documents

This section to be completed by Transmission Business Analyst:

☒ Document Title:
Distribution Generation Interconnection Agreement

☒ Service Commencement date: **7/15/08**

☒ Termination Date: **7/15/18**

☒ FERC filing Date: **n/a**

☒ FERC Acceptance Date: **n/a**

☒ Rate schedule or Service agreement #
n/a

☒ Document was signed by both parties

☒ Execution date: **7/15/08**

☒ Added to Contract Tracking spreadsheet.

1. Was agreement added to the EQR?
☐ **Yes** ☒ **No**
If No: Proceed to step 2.
If Yes:
☐ Agreement has been added to appropriate EQR.

2. Was agreement filed with FERC?
☐ **Yes** ☒ **No**
If No: Proceed to step 3.
If Yes: Please check for the following

FERC filing date: **n/a**

Docket #: **n/a**

FERC acceptance date: **n/a**

☐ Approval letter is attached

☒ **3. Include the following information**
Counterparty Company name:

Threemile Canyon Wind I, LLC

☒ Type of Document (Select one)

Agreement

☒ Document Category (Select one)

Generation Interconnection (a)

☒ Document Sub-Category (Select one

Distribution

4. Place agreement in "Contracts for entry into p8" mailbox.

DATE in Mailbox: 7/21/08

NOTES
Reason not filed

Distribution level interconnection - not FERC jurisdictional

This section to be completed by Office Coordinator:

☑ **Confirm steps 1-4 are completed.**

☑ **Scan this check-sheet first, then FERC acceptance letter (if applicable), then the actual document when scanning document. Scan them all in a single combined document.**

☑ **Enter combined document into p8 using the information given above in step 3.**

☑ **Send an email containing a p8 link to the combined document to the "Final Transmission**

Send executed original to PacifiCorp Contracts and Records Department

Electronic document available at S:\Non-Public Transmission\TRANSMISSION\FERC Filings

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

P.O. Box 2757
Portland, OR 97208-2757

1033 NE 6th Avenue
Portland, OR 97232

July 15, 2008

Richard Free
Threemile Canyon Wind I, LLC
c/o John Deere Credit - Wind Energy
6400 N.W. 86th Street
Johnston, Iowa 50131-6600

Re: Fully Executed Generation Interconnection Agreement for Threemile Canyon Wind I - Q0071

Dear Mr. Free:

Enclosed for your files is a fully executed original of the Distribution Generation Interconnection Agreement ("DGIA") for the Threemile Canyon Wind I, LLC generation facility.

Please contact me at (503) 813-6079 or Raul Huitron-Azcuaga at (503) 813-6102 if you have any questions.

Sincerely,

for
Dennis Desmarais
Director, Transmission Services

Enclosure

PACIFICORP
Transmission Systems

DOCUMENT SUMMARY SHEET

COVER SHEET INFORMATION

Date: July ~~16~~ 15, 2008	Submitted By: Dan Johannsen

DOCUMENT INFORMATION

Company Name: Threemile Canyon Wind I, LLC	
Document Title: Distribution Generation Interconnection Agreement	
Document Type: ☒ Agreement ☐ Amendment ☐ Correspondence ☐ Exhibit ☐ Study Report	
Document Date: July 15, 2008	Contract Execution Date (if applicable): July 15 2008
Contract Effective Date (if applicable): July 15 2008	Contract Termination Date (if applicable): July 15, 2018, and year to year thereafter until terminated by either Party
Project Name (if applicable): Threemile Canyon Wind I	
Queue Position/AREF/Contract Number (if applicable): Q0071	
POD/POR (if applicable):	

DOCUMENT CATEGORY

Click on drop down list and select document category

Generation Interconnection

DOCUMENT SUB-CATEGORY

For the following Document Categories, click on drop down list and select a document sub-category (if applicable):

Generation Interconnection Distribution

Generation Interconnection Studies -Select-

Network Integration Transmission Service -Select-

Point-to-Point Transmission Service -Select-

Transmission Service Studies -Select-

Network Interconnection and Operation -Select-

Other Transmission Interconnection and/or Service -Select-

Engineering and Procurement -Select-

ADDITIONAL COMMENTS

DGIA for 9.9 MW Threemile Canyon Wind I generator interconnection with PacifiCorp's 34.5 kV distribution circuit out of Dalreed Substation near Arlington, Oregon. Not FERC jurisdictional as it is the first generator on a distribution circuit.

SERVICES WITH ASSOCIATED REVENUES

If this Contract or Document has applicable revenues, click the yes box below and check all that apply

Yes!

SERVICES WITH ASSOCIATED EXPENSES

If this Contract or Document has applicable expenses, click the yes box below and check all that apply?

Yes!

DISTRIBUTION INSTRUCTIONS

If this Contract or Document requires an internal distribution, click the yes box below and check all that apply?

Central Files:

☒Central Files-1050 LCT

LCT 1600

☒L. Bahls ☒J. Cupparo ☐P. Deas ☒D. Desmarais ☐B. Fritz ☐B. Gullakson ☒L. Harkins ☒K. Houston
☒D. Johannsen ☐C. Lockman ☐T. Mitchell ☒N. O'Hara ☒L. Raypush ☒V. Stofiel ☐T. Tabor ☒J. Tanneberger

LCT 700

☒E. Knudsen ☐B. Lawrentz ☐D. Yokota

System Power Control Center

☐B. McClelland ☐M. McGrath ☒R. Williams

North Temple Office

☐R. Matheson

Casper, Wyoming

☐D. Raugutt

Legal, Risk, Power Delivery

☐J. Carriere-Wash. DC ☐M. McVee ☐L. Skidmore

Other Internal T. Turnbull, H. Showers, H. Jespersen, R. Huitron-Azcuaga

COME UP REQUIREMENTS

If the Contract has come up requirements, click the yes box below and fill out the following page (Note this feature works best if all of the above information is correctly entered before clicking on the yes box).

Yes!

DISTRIBUTION GENERATOR INTERCONNECTION AGREEMENT (DGIA)
between
PACIFICORP
and
THREEMILE CANYON WIND I, LLC

(1) TABLE OF CONTENTS

Page No.

This Distribution Generator Interconnection Agreement ("Agreement") is made and entered into this 15th day of July, 2008, by PacifiCorp ("Company"), and Threemile Canyon Wind I, LLC ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Company Information

Company: PacifiCorp
Attention: Director, Transmission Services
Address: 825 N.E. Multnomah St., Suite 1600
City: Portland State: Oregon Zip: 97232
Phone: (503) 813-6712 Fax: (503) 813-6893

Interconnection Customer Information

Interconnection Customer: Threemile Canyon Wind I, LLC
Attention: Manager, Wind Administration
John Deere Credit – Wind Energy
Address: 6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Phone: (515) 267-3671 Fax: (515) 267-4235

Interconnection Customer Application No: Q0071

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all Interconnection Requests submitted under the Distribution Generator Interconnection Procedures (DGIP) except for those submitted under the 10 kW Inverter Process contained in DGIP Appendix 5.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Generating Facility will interconnect with, and operate in parallel with, the Company's Distribution System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable entity.

1.4 Nothing in this Agreement is intended to affect any other agreement between the Company and the Interconnection Customer.

1.5 <u>Responsibilities of the Parties</u>

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Company shall construct, operate, and maintain its Distribution System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Company and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Company and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Company's Distribution System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Interconnection Customer shall coordinate with any Affected System owners to determine what, if any, impacts the proposed interconnection will have on such Affected System owners and what, if any, mitigation is required to protect such owners to their reasonable satisfaction. The Company shall confirm that the Interconnection Customer has engaged in the required coordination with Affected System owners and the Company shall not allow the Interconnection Customer to interconnect its Generating Facility to the Company's Distribution System unless and until the Interconnection Customer has mitigated Affected System impacts to the reasonable satisfaction of Affected System owners. The Company may require the Interconnection Customer to provide written evidence of coordination with Affected System owners and written evidence of the mitigation required by such owners. Furthermore, the Company may, at its discretion, coordinate with all Affected Systems to support the interconnection. The Interconnection Customer shall pay all costs associated with mitigation reasonably required by Affected System owners.

1.6 Parallel Operation Obligations

Once the Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Generating Facility in the applicable control area, including, but not limited to the Operating Requirements set forth in Attachment 5 of this Agreement as amended from time-to-time.

1.7 Metering

Unless otherwise determined by the Company, the Interconnection Customer shall be responsible for the Company's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2, 3 and 6 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements. Required metering equipment shall be capable of telephonic meter interrogation. The Interconnection Customer shall obtain, maintain, and pay for, all telephone service required to allow telephonic interrogation of the meter. The form of telephone service selected by the Interconnection Customer must provide reliable data transmission acceptable to the Company.

1.8 Reactive Power

The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Company has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Company of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Company may send qualified personnel to the Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Company a written test report when such testing and inspection is completed and reimburse the Company for all reasonable expenses incurred by the Company in participating in the testing and inspection of the Generating Facility.

2.1.2 The Company shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Company of the safety, durability, suitability, or reliability of the Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Company shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Company shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Company shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Generating Facility in parallel with the Company's Distribution System without prior written authorization of the Company. The Company will provide such authorization once the Company receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Company may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Company at least five Business Days prior to conducting any on-site verification testing of the Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Company shall have access to the

Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Interconnection Customer shall bear its own costs and shall reimburse the Company's costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date. If the Parties have entered into a power purchase agreement under which the Company has agreed to purchase the net output of the Generating Facility from the Interconnection Customer for a specified period of time, then this Agreement shall remain effective until the power purchase agreement has been terminated or has expired by its terms (except for any period under which the power purchase agreement has been extended in accordance with any term extension provision, in which case this Agreement shall continue for a commensurate period).

In all other cases, this Agreement shall remain in effect for a period of ten years from the Effective Date, and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

Notwithstanding the foregoing, if due to any circumstance whatsoever, the Company believes on reasonable grounds that the Generating Facility has come under the jurisdiction of an Open Access Transmission Tariff required by the Federal Energy Regulatory Commission ("FERC"), the Interconnection Customer shall, if required by the Company and within a reasonable time from receiving written notice from the Company of its belief, enter into a replacement interconnection agreement that conforms to a pro-forma interconnection agreement contained in the Company's Open Access Transmission Tariff or an interconnection agreement that is accepted for filing by FERC and this Agreement will immediately terminate in its entirety on execution of the replacement agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Company 20 Business Days written notice.

3.3.2 Either Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Generating Facility will be disconnected from the Company's Distribution System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this DGIA or such non-terminating Party otherwise is responsible for these costs under this DGIA.

3.3.4 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions -- "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Company, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Distribution System, the Company's Facilities or the transmission systems or distribution systems of others to which the Distribution System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the Company may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Company shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Company promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Company's Distribution System, the Company's Transmission System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Company may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Company's Distribution System when necessary for routine maintenance, construction, and repairs on the Company's Distribution System or the Company's Transmission System. The Company shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The Company shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Company may suspend interconnection service to effect immediate repairs on the Company's Distribution System. The Company shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Company shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Company shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generating Facility could cause damage to the Company's Distribution System, the Company's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Company may disconnect the Generating Facility. The Company shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Generating Facility

The Interconnection Customer must receive written authorization from the Company before making any change to the Generating Facility that may have a material impact on the safety or reliability of the Distribution System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Company's prior written authorization, the latter shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Company's Distribution System or Transmission System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Company shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Company.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Company's Interconnection Facilities.

4.2 Distribution Upgrades

The Company shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Company and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Company shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Company and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Company elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne by the Interconnection Customer.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Company shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties.

6.1.2 Within three months of completing the construction and installation of the Company's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Company shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Company for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Company shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Company within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Company shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Company's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Company, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Company and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Company's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Company under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Company, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Company and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 <u>Assignment</u>

This Agreement may be assigned by either Party upon 15 Business Days prior written notice and opportunity to object by the other Party; provided that:

7.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Company of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Company, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will promptly notify the Company of any such assignment.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 <u>Limitation of Liability</u>

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control; a Force Majeure Event does not include an act of negligence or intentional wrongdoing."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be for an amount that is reasonably acceptable to the Company taking into account the circumstances and location of the Interconnection Facilities. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Company, except that the Interconnection Customer shall show proof of insurance to the Company no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 The Company agrees to maintain general liability insurance or self-insurance consistent with the Company's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Company's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.3 Notwithstanding anything in this article to the contrary and only to the extent consistent with the applicable state rules and regulations, if a state regulatory body, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the state regulatory body, within the time provided for in the request for information. In providing the information to the state regulatory body, the Party may request that the information be treated as confidential and non-public by the state regulatory body and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this Agreement prior to the release of the Confidential Information to the state regulatory body. The Party shall notify the other Party to this Agreement when it is notified by the state regulatory body that a request to release Confidential Information has been received by the state regulatory body, at which time either of the Parties may respond before such information would be made public.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may initiate non-binding mediation under the American Arbitration Association's Commercial Mediation Rules in an attempt to resolve the dispute.

10.4 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

10.5 If neither Party elects to attempt mediation or if the attempted mediation fails then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement and the terms of the Company's Distribution Generation Interconnection Procedures.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Company's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of Oregon (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights, if any, to obtain an interconnection from the Company. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All electric providers, market participants, and Interconnection Customers interconnected to electric systems are expected to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Company be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Company shall have the right to make a unilateral filing with the appropriate state utility commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation or any applicable provision of state or federal law and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the appropriate state utility commission to modify this Agreement under any applicable provision of state or federal law and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the appropriate state utility commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the appropriate state utility commission under state or federal law and regulations, except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:
Interconnection Customer: Threemile Canyon Wind I, LLC
Attention: Terry Kramer, Manager, Wind Administration

John Deere Credit – Wind Energy
Address6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Phone: (515) 267-3671 Fax: (515) 267-4235

with a copy to:

Jeffery Karch, Assistant Chief Counsel
c/o John Deere Credit – Wind Energy
Address: 6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Phone: (515) 267-4404 Fax: (515) 267-4235

If to the Company:

Company: PacifiCorp
Attention: Director, Transmission Services
Address: 825 N.E. Multnomah St., Suite 1600
City: Portland State: Oregon Zip: 97232
Phone: (503) 813-6712 Fax: (503) 813-6893

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: Threemile Canyon Wind I, LLC
Attention: Dawn Christensen, Accountant
c/o John Deere Credit – Wind Energy
Address: 6400 N.W. 68th Street
City: Johnston State: Iowa Zip:50131-6600
Phone; (515) 267-4653 Fax: (515) 267-4235

Company: PacifiCorp Transmission
Attention: Central Cashiers
Address: P.O. Box 2757
City: Portland State: Oregon Zip: 97208-2757

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: Threemile Canyon Wind I, LLC
Attention: Terry Kramer, Manager, Wind Administration
c/o John Deere Credit – Wind Energy

Address: 6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Phone: (515) 267-3671 Fax: (515) 267-4235

with a copy to:
Jeffery Karch, Assistant Chief Counsel
c/o John Deere Credit – Wind Energy
Address: 6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Phone: (515) 267-4404 Fax: (515) 267-4235

If to the Company:

Company: PacifiCorp
Attention: Director, Transmission services
Address: 825 N.E. Multnomah St., Suite 1600
City: Portland State: Oregon Zip: 97232
Phone: (503) 813-6712 Fax: (503) 813-6893

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: Threemile Canyon Wind I, LLC
Attention: Magin Reyes, Wind Operations & Maintenance Manager
c/o John Deere Credit – Wind Energy
Address: 6400 N.W. 86th Street
City: Johnston State: Iowa Zip: 50131-6600
Cell: (515) –422-1686 Fax: (515) 267-4235

Company's Operating Representative:

Company: PacifiCorp
Attention: Grid Operations
Address: 9915 S.E. Ankeny St.
City: Portland State: Oregon Zip: 97216
Phone: (503) 251-5197 Fax: (503) 251-5228

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

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

For the Company

Name: [signature]

Title: Director, Transmission

Date: July 15, 2008

For the Interconnection Customer

Name: [signature]

Title: MANAGER

Date: 7/11/08

Attachment 1 to DGIA

Glossary of Terms

Affected System – An electric system other than the Company's Transmission System or Distribution System that may be affected by the proposed interconnection.

Agreement – The Company's Distribution Generator Interconnection Agreement or DGIA.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Business Day – Monday through Friday, excluding Federal Holidays.

Company – PacifiCorp, an Oregon Corporation.

Default – The failure of a breaching Party to cure its breach under the Distribution Generator Interconnection Agreement.

Distribution Generator Interconnection Procedures (DGIP) – The Company's procedures for processing requests to interconnect a Generator with the Company's Distribution System where the requested interconnection is not governed by, or subject to, the Federal Energy Regulatory Commission's interconnection procedures under its Order No 2003 or Order No. 2006.

Distribution System – The Company's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas but unless otherwise determined by the Company does not exceed 45 kV. The Distribution System is an aspect of, and interconnected with, the Company's larger electric power system that includes the Company's Transmission System.

Distribution Upgrades – The additions, modifications, and upgrades to the Company's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility. Distribution Upgrades do not include Interconnection Facilities.

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

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

Interconnection Customer – Any entity that proposes to interconnect its Generating Facility with the Company's Distribution System.

Interconnection Facilities – The Company's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Company's Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Company's Distribution Generator Interconnection Procedures, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Company's Distribution System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Company's Transmission System required to accommodate the impacts on the Company's Transmission System resulting from the interconnection of the Generating Facility with the Company's Distribution System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, control area, or the Company's requirements, including those set forth in the Distribution Generator Interconnection Agreement.

Party or Parties – The Company, Interconnection Customer or both.

Point of Interconnection – The point where the Interconnection Facilities connect with the Company's Distribution System.

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

Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

System Owner – The Company or any entity that owns, leases or otherwise possesses an interest in any Affected System.

Transmission System – The facilities owned, controlled or operated by a System Owner that are used to provide transmission service.

Upgrades – The required additions and modifications to the Company's Distribution System or Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2 to DGIA

Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Small Generating Facility: A 9.9 MW wind generating facility composed of six (6) 1.65 MW Vestas V82 wind turbines and 34.5 kV, one feeder, collector system. (See Attachment 3)

Interconnection Customer Interconnection Facilities: The 34.5 kV cable from the first wind turbine; new switchyard, a main fault interrupting device, and a grounded wye primary – delta secondary grounding transformer bank and fault interrupting device. (See Attachment 3)

Company Interconnection Facilities: A 34.5 kV breaker and associated switches, relay protection panel, RTU, microwave communication facilities and revenue metering located within the Interconnection Customer's new switchyard. (See Attachment 3).

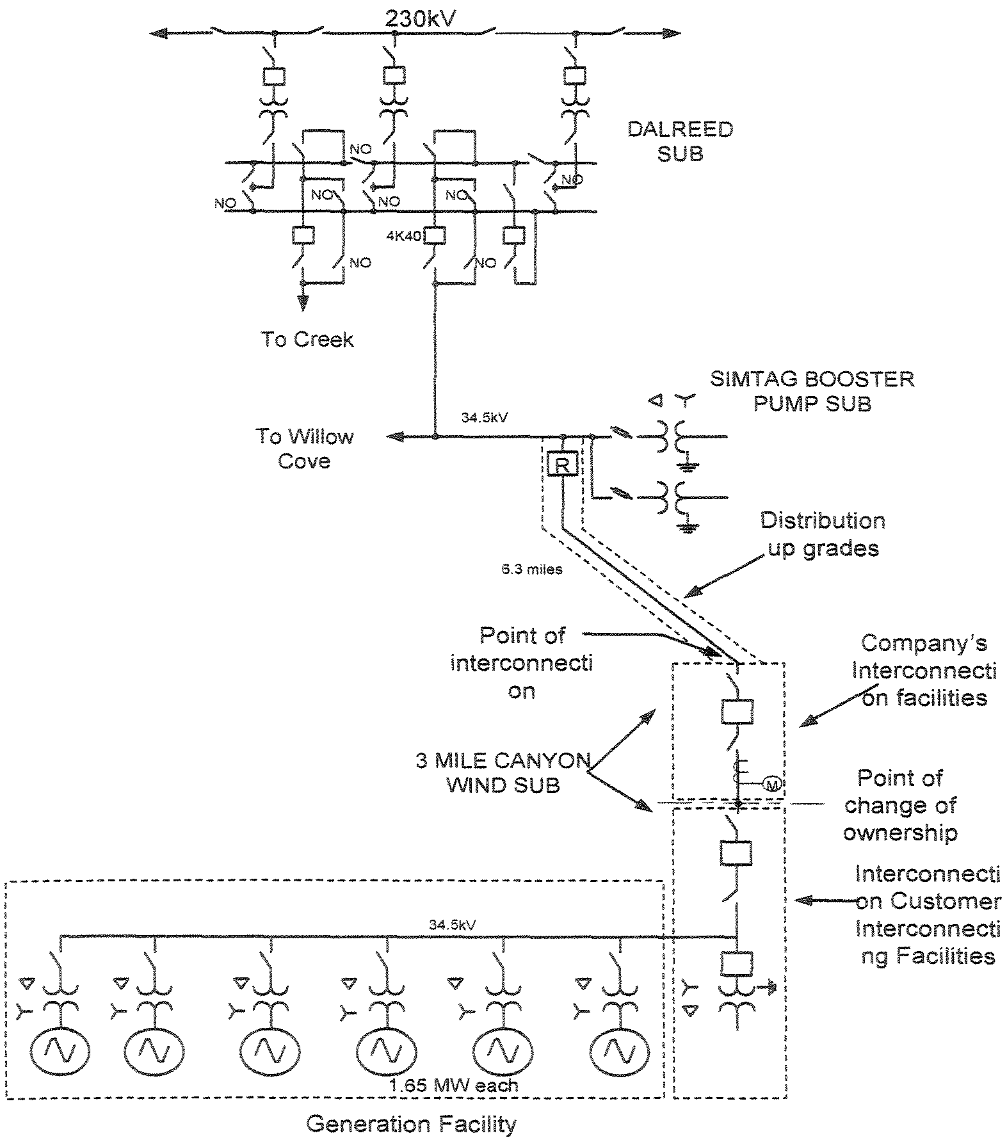
Estimated Operations and Maintenance cost for Company Interconnection Facilities is $15,867. In reference to Article 4.1.2 of this Agreement, Interconnection Customer will be charged Operations and Maintenance costs for Company Interconnection Facilities, under a separate agreement.

Point of Change of Ownership: The point within the Interconnection Customer's switching station where the Company's 34.5 kV circuit breaker switch connects to Interconnection Customer's Interconnection Facilities. (See Attachment 3)

Point of Interconnection: The point where the Company's 34.5 kV circuit breaker switch, located within the Interconnection Customer's switching station, connects to the new 34.5 kV distribution line. (See Attachment 3)

Attachment 3 to DGIA

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades



Attachment 4 to DGIA

Milestones

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Company Commences Engineering – July 1, 2008	Company
(2)	Company Commences Construction of its Scope of Work – July 1, 2008	Company
(2)	In Service Date (Back Feed) – December 31, 2008	Company and Interconnection Customer

Interconnection Customer shall request in writing and obtain written approval from Company to energize the interconnection. Company shall not unreasonably withhold such approval, which shall be granted in writing. In-Service date is contingent upon Company being able to acquire outside design support to complete Company's protection and control scope of work.

(3)	Initial Synchronization Date – January 15, 2009	Company and Interconnection Customer

Interconnection Customer shall request in writing and obtain written approval from Company to synchronize the first unit. Company shall not unreasonably withhold such approval, which shall be granted in writing.

(4)	Commercial Operation Date – January 31, 2009	Interconnection Customer

Interconnection Customer shall request in writing and obtain written approval from Company to begin commercial operation. Company shall not unreasonably withhold such approval, which shall be granted in writing. Within five business days of Commercial Operations, Interconnection Customer will notify Company in writing of the actual Commercial Operations Date.

Work Progress: At the end of each month, Interconnection Customer shall provide Company a progress report describing the Distribution Upgrades, Network Upgrades and Direct Assigned Facilities that have been completed by the Interconnection Customer during the preceding month. Such report shall include the actual cost to date expended for labor and material and expenses for each Distribution Upgrade, Network Upgrade facility and Direct Assigned Facility, the projected expenditure for the next month and the projected final cost.

Accounting for Facilities Constructed by Customer: Interconnection Customer shall account for the cost of Distribution Upgrades, Network Upgrade and Direct Assigned Facilities in accordance with Attachment 8, Facilities Accounting Requirements.

Attachment 5 to DGIA

Additional Operating Requirements for the Company's Distribution System and Affected Systems Needed to Support the Interconnection Customer's Needs

Operating Requirements: Interconnection Customer shall interconnect and operate the Generating Facility in accordance with the Company's Generation Interconnection for Distribution Systems attached hereto as Attachment 9.

Reactive Power. Consistent with DGIA Article 1.51, and Attachment 9, Sections G2.12 and G3.1.1.1, the Generating Facility must be designed to deliver power to the Point of Interconnection at unity power factor, when the generator is operating at full output, and the voltage at the Point of Interconnection is 1.0 pu. Power factor correction devices to achieve this requirement must be located outside the switching station. The Company's power quality standards state planning levels for voltage flicker are to be limite3d to a $P_{st} < .9$ and a $P_{lt} < .7$ for this project. This includes flicker caused by capacitor switching and flicker due to the wind turbine operation. The Interconnection Customer has supplied data to show this project will not create voltage flicker beyond these standards. If during operation of this Generating Facility, voltage flicker levels are measured beyond the Company's standards, corrective actions by the Interconnection Customer, will be required, at its expense.

Protection. The Company shallown and maintain, at Interconnection Customer's expense: a relay protection (line, under/over frequency, under/over voltage) panel. The frequency and voltage protection will trip wind turbine feeder breakers in accordance with settings shown in Attachment 9, Section 5.

Low Voltage Ride Through. The wind turbines will be expected to meet the WECC low voltage ride through requirements.

Attachment 6 to DGIA

Company's Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: A 6.3 mile 34.5 kV distribution line extension with attached fiber optic communication cable from a point on Company's existing Simtag 34.5 kV distribution feeder to the new switching station; a 34.5 kV recloser and three 34.5 kV voltage transformers and secondary connection from the transformers to the recloser where the line extension connects to the existing Simtag feeder; replacement of 34.5 kV circuit breaker #4K46 and installation of three 34.5 voltage transformers on the Simtag #2 feeder and associated protection and control upgrades at Dalreed Substation.

Estimated cost of Company's Distribution Upgrades:

$1,552,091

Estimated Annual Operation and Maintenance Expense: $0

Network Upgrades: Communications upgrades at Company's Dalreed and Walla Walla Substations, Portland Control Center, Kennewick and Yakama Service Centers and Roosevelt Mt. Communication Site required to transfer the Small Generation Facility operation and control data to Company's control center.

Estimated cost of Company's Network Upgrades:

Network Upgrades: $57,787

Estimated Annual Operation and Maintenance Expense: $0

Attachment 7 to DGIA

Scope of Work

Company's 34.5-kV Distribution Interconnection

Location: Boardman, Oregon.

Property/Permitting/Right of Way (ROW)/Easements: One third party easement will be required for the distribution tap line and switchyard. The Interconnection Customer will be responsible for obtaining this perpetual easement for Company on the Company's standard easement forms including a surveyed description of the easement. One permit will be required from PGE in order for Company's distribution line to cross under PGE's 500kV line. The Company will obtain this permit, however while no problems are foreseen there is no guarantee of success in obtaining this permit.

34.5 kV Distribution Line Construction: Construct a 6.3 mile, 34.5 kV distribution line extension from a point near the Simtag Booster Pump Substation generally South to the new Collector Substation. The first 1.3 miles will be a rebuild of an existing two phase small wire line owned by the Company. The remaining 5.0 miles of this extension will be new construction. This 6.3 mile route has the initial approval from the land owner and will consist of three 397 ACSR primary conductors with one 4/0 ACSR neutral conductor. Poles installed for this line will have adequate height for a Company communication fiber to be installed in the supply space while maintaining required clearances.

Near the Simtag Booster Pump Substation at the beginning of the distribution line tap a 34.5kV recloser, three 34.5 kV voltage transformers, and a secondary connection from these transformers to the recloser will be installed. This recloser will feed the new and rebuilt 34.5kV line to the switching station from the 34.5kV Simtag Feeder. The source for the Simtag Feeder is Dalreed Substation.

All of the above 34.5 kV distribution line construction will be designed , procured, constructed and owned by the Company.

Communications for Line Protection: The protective relaying circuits between the generating facility and the circuit recloser will be placed on single-mode fiber. The fiber length from the recloser to the collector site is approximately 6.3 miles. Patch panels will be installed at both sites to terminate the fibers. The communications medium between the relays will be direct fiber. All of the fiber optic cable will be procured and installed by the Company. The fiber optics will be designed, terminated and tested by the Company.

The protective relaying circuits between the Dalreed Substation and the Generating Facility will be over Microwave path. All Microwave Communications will be designed, procured, installed and tested by Company.

Interconnection Customer's Switching Station

Substation: Construct a new 34.5kV Switching Station that is to connect to the new Interconnection Customer Generation Facility to Company's Dalreed Substation, via the Simtag 34.5kV distribution feeder. The new switching station will include two 34.5 kV fault interrupting devices: a breaker on the new incoming feeder segment from Simtag, and a breaker/fault interrupting device protecting the Interconnection Customer's wind turbine feeder. The switching station will be designed to have space to include a second wind turbine feeder breaker/fault interrupting device should phase II of the interconnect project be built in the future. The Interconnection Customer will be responsible for procuring the property for the switching station. The engineering, procurement and construction of the Switching Station will be performed by the Interconnection Customerwith Company Engineering reviewing the design. Company will be responsible for all checkout and testing of the Company owned new equipment located within the new switching station.

Protection & Controls: The Interconnection Customer will design, procure and install the protection & control (P&C) panels in an enclosure to be owned by the Interconnection Customer in the new switching station. Physical and electronic access to such enclosure and the Company's equipment within iy, compliant with Interconnection Customer's policies, will be provided to the Company. The Main Breaker panel will be owned and maintained by the Company and the Company will approve the design of this panel before it is procured by the Interconnection Customer. Company will also provide all relay settings for the new Main Breaker relays and clearing times for the Feeder Breaker relays. The P&C panels will consist of the following:

Main Breaker panel

1 – Company's Standard panel PC130, line protection, metering and breaker control panel, with the addition of SEL-2815 fiber-optical transceivers connected to port 2 on both SEL-321, 1 – Switch, Telephone, Line Sharing; Teltone Part #M-394-B01, 1 – Modem; Teltone Part #MOD-2, 1 – Switch, Data; Teltone Part #DS-108-A02, and 1 – GPS Satellite controlled clock; Arbiter type 1084B.

Generation Collector Feeder Breaker panel

1 – Functionally similar to Company's Standard panel PC610, feeder protection and breaker control panel, except with a vertical mount SEL-351A relay instead of the ABB DPU2000R relay.

Annunciator panel

1 – Company's Standard panel PI111 panel.

A dialup telephone lease circuit will be connected to the telephone line sharing switch on the P&C panel. Through this switch the Company will be able to access fault records from the protective relays and read the registers in the interchange meters.

The Company will design, procure, own and maintain a Harris D20 RTU to be installed in the switching station. With this RTU the Company will remotely control and monitor the breakers in the substation. With the RTU the alarms for the substation equipment and the power flows will be monitored. The Interconnection Customer will need to provide an analog (0-1ma) signal of the wind speed to be connected to an input on the RTU. The RTU will communicate via microwave to Dalreed Substation and from the Substation to Company's Control Center in Portland via the Company's microwave communication network.

The Company will design, furnish, and install a telemetering transmitter (RFL 9800) that will take the real power signal from the interchange meters and send that signal to Company's Energy Control Center in Portland. This signal will also be carried over microwave to Dalreed Substation and then the Company's microwave communication network to Company's Control Center in Portland.

Communications: Coastcom R-409 Integrated Access Devices will be installed at the collector substation. Circuits required for SCADA, telemetry, and voice and data dial-up will be routed through the R-409s and Microwave. An RFL 9800 shelf and transmitter will be installed at the collector substation for transmission of the real-time line MW value. A new Microwave tower, antennae and associated equipment will also be installed at the Collector Substation. The SCADA, telemetry, and dial-up circuits will then be cross-connected to existing Company microwave at Dalreed Substation. All of the engineering, procurement, installation and testing of all Communications equipment will be the responsibility of Company.

Metering: Primary and Back-up meters will be installed on the distribution line side of the Point of Change of Ownership in the Company's Interconnection Facilities at the new switching station.

The Interconnection Customer will design, procure, and install the metering instrument transformers and metering control cable. The instrument transformers and control cable must be approved by the Company before they are procured to meet Company metering standards. Three current transformers and three voltage transformers will be required and shall be 0.3% metering accuracy. The current transformers must be capable of maintaining their accuracy from a range of 50KW to 9.9MW. The control cable shall be manufactured by Draka and will be Company stock # 3090335 for the Current cable, and Company Stock # 3090336 for the Voltage cable.

The Company will design, procure, and install a metering panel inside the Interconnection Customer's new Switching Station. The panel will include two Landis + Gyr 2510 bi-directional meters to measure generation received from the customer and retail load delivered to the customer. The primary meter will be used for SCADA and MV-90 data acquisition. The back-up meter will be used for telemetry and secondary dial-up. Both meters will include DNP3.0 and analog outputs for SCADA and telemetry communications. A dial-up phone will be required for the MV-90 translation system. This can be accommodated through the Dalreed Substation and then over the microwave to the Interconnection Customer's new Switching Station.

Company's Dalreed Substation – Install Upgrades

Substation: Install three 34.5kV voltage transformers on the Simtag #2 distribution feeder. Replace the over-dutied breaker 4K46 with a new 34.5kV, 1200Amp breaker. All of the engineering, procurement, installation and testing will be the responsibility of Company.

Protection & Controls:

Breaker Replacement

One 1200A 34.5kV breaker will be installed in breaker position 4K46. As part of this breaker replacement 1 ea. – Company's Standard panel PC610, feeder protection and breaker control panel, will be installed.

<u>Simtag Feeder Breaker Position</u>

2 – SEL 2505 Remote I/O modules will be installed to provide transfer trip to the switching station. A three phase set of 34.5kV voltage transformers will be installed on the line side of this breaker position. The secondary of these voltage transformers will be wired into the existing feeder protective relay. The relay will be reconfigured to delay reclosing of the breaker until there is an indication that the line is not energized.

<u>230 – 34.5kV Transformer LTC Control</u>

The LTC controls on the three 230 – 34.5kV transformers need to have the settings modified to function correctly in the condition that the power is flowing in the reverse direction through the transformer.

Communications: Coastcom R-409 Integrated Access Devices will be installed at the Dalreed Substation. Circuits required for SCADA, telemetry, and voice and data dial-up will be routed through the R-409s and fiber. From the Dalreed Substation, the SCADA circuit will be routed to Portland Control Center (PCC); the telemetry circuit will be routed to Yakima Customer Service Center and PCC and the dial-up circuits will be routed to Yakima Customer Service Center. All of the engineering, procurement, installation and testing will be the responsibility of Company.

Company's Simtag Booster Pump – Install Recloser

Protection & Controls:

<u>Simtag Booster Pump Recloser</u>

The Company will design, procure, install, own and maintain a 34.5kV electronic recloser. This recloser will be equipped with directional phase and neutral overcurrent elements and dead line check on reclosing. To accommodate this equipment a set of three 34.5kV voltage transformers will need to be mounted on the generation side of the recloser. Also mounted in the recloser control cabinet will be two SEL-2505 remote I/O modules.

Company's Portland Control Center – Install Communication Equipment

Communications: Install Coastcom and RFL hardware. This is required in order to bring SCADA data from the site back to PCC. Engineering, procurement, installation and testing will be the responsibility of Company.

Company's Kennewick Service Center – Install Communication Equipment

Communications: Install Coastcom and modem hardware. This is required in order to bring SCADA data from the generation site back to PCC. Engineering, procurement, installation and testing will be the responsibility of Company.

Company's Walla Walla Substation – Install Communication Equipment

Communications: Install Coastcom hardware. This is required in order to bring SCADA and telemetry data from the generation site back to PCC. Engineering, procurement, installation and testing will be the responsibility of Company.

Company's Yakima Service Center – Install Communication Equipment

Communications: Install Coastcom, RFL and modem hardware. This is required in order to bring telemetry data from the generation site back to the Yakima Service Center. Engineering, procurement, installation and testing will be the responsibility of Company.

Company's Roosevelt Mt. Comm Site – Install Communication Equipment

Communications: Install modem hardware. This is required in order to bring SCADA data from the generation site back to PCC. Engineering, procurement, installation and testing will be the responsibility of Company.

Generating Facility Modifications

Interconnection Customer will be responsible for engineering, procurement and design of these requirements.

Transformer Configuration: The transformer installed at each wind turbine site will be a delta primary (high voltage) – grounded wye secondary (low voltage) configuration. The interconnection customer is to also install one grounded wye primary – delta secondary grounding transformer bank prior to when the first wind turbine generates energy. All wind turbine step-up transformers will have single phase protection (bayonet fusing) and will also have an internal or external three phase ganged switch to provide a means to connect and/or disconnect all phases of the primary simultaneously.

Power Factor Correction and Voltage Ride Through: The Generating Facility must be designed to deliver power to the Point of Interconnection at unity power factor, when the generator is operating at full output, and the voltage at the Point of Interconnection is 1.0 pu. Power factor correction devices to achieve this requirement must be located outside the switching station. The Generating Facility must be designed to meet the Western Electricity Coordinating Council ("WECC") low voltage ride through requirement.

Attachment 8 to DGIA

Facilities Accounting Requirements

Interconnection Customer shall account for the cost of labor and material for Network Upgrades, Distribution Upgrades and Direct Customer Assigned Facilities, funded and constructed by the Interconnection Customer but owned by the Company, in accordance with the following Asset Account Property Unit list. Such accounting is required to allow Company to properly account for the cost of Network Upgrades, Distribution Upgrades and Direct Assigned Facilities in its property account records.

DETAIL OF ACTUAL COST

TITLE:

FERC ACCOUNT:

LOCATION:

Project name/number

Network Upgrades - cost of customer installed facilities on behalf of PacifiCorp - Assets should be booked at full value.

RETIREMENT UNIT	QTY	PRU #	Units	Material Cost	Labor Cost
LAND		00001			
RIGHT OF WAY/EASEMENTS		00002			
AUTOMATIC TRANSFER SWITCH		22004			
CABLE TRAY		22013			
ROADWAY		22017			
CLEARING, GRADING & FILL MATERIAL		22018			
CONTROL BUILDING		22025			
UNDERGROUND ENCLOSURE (MANHOLE)		22036			
FENCE & GATES		22038			
LIGHTING FIXTURE		22040			
FOUNDATION AND SUBSTRUCTURE		22044			
GENERATOR		22046			
LANDSCAPING W/SPRINKLING SYSTEM		22060			
DRAINAGE SYSTEM		22072			
RETAINING WALL		22082			
SIDEWALK		22092			
OIL SPILL CONTAINMENT		22097			
MINOR STRUCTURE		22104			
UNINTERRUPTIBLE POWER SUPPLY		22110			
LOAD CENTER		22121			
BUILDING (NOT CONTROL BLDG OR MINOR)		22122			
DIGITAL FAULT RECORDER		23421			
SATELLITE CLOCK		23691			
POWER TRANSFORMER		25110			
COUPLING CAPACITOR VOLTAGE TRANSFORMER		25135			
VOLTAGE TRANSFORMER (include voltage rating-138kV metering acc)		25140			
CURRENT TRANSFORMER (include voltage rating-138kV metering acc)		25145			
STATION SERVICE TRANSFORMER		25160			
RECTIFIER/INVERTER		25170			
REACTOR		25173			
REGULATOR		25200			
BREAKER		25300			
RECLOSER		25310			
INTERRUPTER SWITCH		25340			
FAULT INTERRUPTER		25341			
AIRBREAK SWITCH (include voltage and current ratings)		25400			
HOOK OPERATED SWITCH		25420			
DISCONNECT SWITCH		25420			
REGULATOR BY-PASS SWITCH		25421			
LOAD INTERRUPTING SWITCH		25422			
GROUP OPERATED SWITCH - include voltage and current rating		25424			
GROUND SWITCH		25427			
SWITCH		25436			
POWER FUSE WITH END FITTINGS		25440			
POWER FUSE		25441			
CIRCUIT SWITCHER		25450			
TRANSRUPTER		25455			
CAPACITOR BANK		25460			
METAL CLAD SWITCH GEAR		25470			
STEEL STRUCTURE		25510			
POLES (include height and type - steel/concrete/wood)		25521			
CABLE TRENCH		25540			
CONDUIT		25550			

GROUND GRID		25551					
GROUND MAT		25555					
BUS		25610					
ANIMAL GUARDS		25618					
LIGHTNING ARRESTER		25620					
CUTOUT		25625					
INSULATOR, DISC		25630					
INSULATOR, POST - include voltage class and type (polymer/glass)		25631					
TERMINATOR (POTHEAD)		25632					
INSULATOR, SUSPENSION - include voltage class and type (polymer/glass)		25634					
INSULATOR - STRAIN - include voltage class and type (polymer/glass)		25635					
POWER & CONTROL CABLE		25640					
INSULATED PLATFORM		25650					
RELAY AND CONTROL		25700					
BATTERY AND RACK		25800					
BATTERY CHARGER		25801					
REMOTE TERMINAL UNIT		26100					
INTERPOSITION CABINET		26101					
MASTER STATION		26102					
SEQUENCE OF EVENTS RECORDER		26103					
LTC PROGRAMMABLE POSITION MONITOR		26104					
HMI AUTOMATION(PC, PRINTER, SOFTWARE)		26105					
BASE STATION		27105					
MAS SCADA REMOTE RADIO		27125					
POWER CONVERTER (A/C OR D/C)		27610					
		TOTAL					

DETAIL OF ACTUAL COST

TITLE:

FERC ACCOUNT:
LOCATION:

Project name/number

Direct Customer Assigned Facilities installed by customer and owned by PacifiCorp - Assets should be booked at zero value.

RETIREMENT UNIT	QTY	PRU #	Units	Material Cost	Labor Cost
LAND		00001			
RIGHT OF WAY/EASEMENTS		00002			
AUTOMATIC TRANSFER SWITCH		22004			
CABLE TRAY		22013			
ROADWAY		22017			
CLEARING, GRADING & FILL MATERIAL		22018			
CONTROL BUILDING		22025			
UNDERGROUND ENCLOSURE (MANHOLE)		22036			
FENCE & GATES		22038			
LIGHTING FIXTURE		22040			
FOUNDATION AND SUBSTRUCTURE		22044			
GENERATOR		22046			
LANDSCAPING W/SPRINKLING SYSTEM		22060			
DRAINAGE SYSTEM		22072			
RETAINING WALL		22082			
SIDEWALK		22092			
OIL SPILL CONTAINMENT		22097			
MINOR STRUCTURE		22104			
UNINTERRUPTIBLE POWER SUPPLY		22110			
LOAD CENTER		22121			
BUILDING (NOT CONTROL BLDG OR MINOR)		22122			
DIGITAL FAULT RECORDER		23421			
SATELLITE CLOCK		23691			
POWER TRANSFORMER		25110			
COUPLING CAPACITOR VOLTAGE TRANSFORMER		25135			
VOLTAGE TRANSFORMER (include voltage rating-138kV metering acc)		25140			
CURRENT TRANSFORMER (include voltage rating-138kV metering acc)		25145			
STATION SERVICE TRANSFORMER		25160			
RECTIFIER/INVERTER		25170			
REACTOR		25173			
REGULATOR		25200			
BREAKER		25300			
RECLOSER		25310			
INTERRUPTER SWITCH		25340			
FAULT INTERRUPTER		25341			
AIRBREAK SWITCH (include voltage and current ratings)		25400			
HOOK OPERATED SWITCH		25420			
DISCONNECT SWITCH		25420			
REGULATOR BY-PASS SWITCH		25421			
LOAD INTERRUPTING SWITCH		25422			
GROUP OPERATED SWITCH - include voltage and current rating		25424			
GROUND SWITCH		25427			
SWITCH		25436			
POWER FUSE WITH END FITTINGS		25440			
POWER FUSE		25441			
CIRCUIT SWITCHER		25450			
TRANSRUPTER		25455			
CAPACITOR BANK		25460			
METAL CLAD SWITCH GEAR		25470			

STEEL STRUCTURE		25510				
POLES (include height and type - steel/concrete/wood)		25521				
CABLE TRENCH		25540				
CONDUIT		25550				
GROUND GRID		25551				
GROUND MAT		25555				
BUS		25610				
ANIMAL GUARDS		25618				
LIGHTNING ARRESTER		25620				
CUTOUT		25625				
INSULATOR, DISC		25630				
INSULATOR, POST - include voltage class and type (polymer/glass)		25631				
TERMINATOR (POTHEAD)		25632				
INSULATOR, SUSPENSION - include voltage class and type (polymer/glass)		25634				
INSULATOR - STRAIN - include voltage class and type (polymer/glass)		25635				
POWER & CONTROL CABLE		25640				
INSULATED PLATFORM		25650				
RELAY AND CONTROL		25700				
BATTERY AND RACK		25800				
BATTERY CHARGER		25801				
REMOTE TERMINAL UNIT		26100				
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BASE STATION		27105				
MAS SCADA REMOTE RADIO		27125				
POWER CONVERTER (A/C OR D/C)		27610				
		TOTAL				

Attachment 9 to DGIA

Generation Interconnection for Distribution Systems

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Policy

GENERATION INTERCONNECTION FOR DISTRIBUTION SYSTEMS (34.5 kV and below)

Author:	Paul Della
Approval:	Greg Lyons
Authoring Department:	Standards Engineering
Approved File Location:	Pdxshrn104\shr04\Eng\Publications\
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List of Figures

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Policy

List of Tables

Appendices

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GENERATION INTERCONNECTION FOR DISTRIBUTION SYSTEMS (34.5 kV and below)

1 INTRODUCTION

This PacifiCorp Generation Interconnection Policy explains the technical requirements for interconnection of generators to PacifiCorp's distribution power systems. It is based on applicable rules and tariffs crafted by the Federal Energy Regulatory Commission (FERC) and jurisdictional state regulatory agencies. In addition to providing reliability, this policy is consistent with safety requirements for PacifiCorp employees and the general public.

Although this policy addresses certain aspects of interconnection cost responsibility, its scope is primarily technical and does not include the commercial requirements for receiving distribution service, nor does it cover generation service from PacifiCorp. Tariffs and rules filed with FERC and jurisdictional state regulatory agencies address the rates, terms and conditions under which PacifiCorp provides these services. If there are any inconsistencies between this policy and the tariffs and rules, the tariffs and rules shall retain control.

1.1 Introductory Definitions

PacifiCorp Power System: For the purposes of this policy, the PacifiCorp power system is defined as electric distribution facilities owned by PacifiCorp.

Customer Load: A person, company, or corporation interconnected to The PacifiCorp power system owning or operating only power-consuming facilities.

Interconnection Customer: A person, company, or corporation interconnected to The PacifiCorp power system owning or operating generation facilities (including back-up and emergency generation).

Any connected entity owning or operating both power-consuming and power-generating facilities shall be considered an interconnection customer for the purposes of this policy, since the technical requirements for interconnection of generation sources are most comprehensive. Any load-only entity which is interconnected to a third-party electric system having generation capabilities shall also be considered an interconnection customer for the purposes of this policy. Technical requirements for multi-interconnected and network systems (systems interconnected to the PacifiCorp power system in addition to a third-party system) will be determined by PacifiCorp on a case-by-case basis.

1.2 Applicability

This policy applies to retail and wholesale entities which are physically connected to or desire to physically connect to PacifiCorp's distribution system. Applicability is further defined by the categories below:

1.2.1 New and Decommissioned Generation Projects

All technical requirements described or referred to in this policy apply to new generation projects. New generation projects are entities which have not been and are not yet connected with the PacifiCorp power system. Additional technical requirements may apply to special business arrangements or electrical configurations of The PacifiCorp power system or the interconnection point(s). Any such technical specifications would be documented through the interconnection agreements (i.e., generation interconnection, operation and maintenance agreement, generation interconnection facilities agreement).

1.2.2 Existing Customer Loads

Retail: All applicable technical requirements described or referred to in this policy apply to existing customer loads. Existing customer loads are loads which have previously established an interconnection with the PacifiCorp power system. To the extent this policy contains more stringent requirements than were in place at the time the customer load initially connected, the existing customer load shall be responsible for adhering to the most recent requirements. The cost for such upgrading shall be borne by either the customer load or by PacifiCorp pursuant to applicable customer load and PacifiCorp.

Wholesale: Existing contracts govern the technical interconnection requirements for existing wholesale loads. Unless modified through mutual agreement or unless PacifiCorp's current or future requirements apply pursuant to the terms of existing contract, the technical provisions of these existing agreements (e.g., with municipal utilities, federal power marketing agencies, and investor-owned utilities) concerning physical interconnection remain applicable. For information concerning the interconnection and operation of loads under these agreements please contact PacifiCorp's Distribution Account Manager.

1.2.3 Existing Generation Projects

All the applicable technical requirements described or referred to in this policy may not apply to existing generation projects. Existing generation projects are entities which have previously established an interconnection with the PacifiCorp power system.

To the extent this policy contains more stringent requirements than were in place at the time the generation projects initially connected, the existing entity shall be responsible for adhering to current requirements only to the extent that the safety and reliability of the power system or the safety of utility employees would be jeopardized by not adhering to the current requirements and policies. The cost for such upgrading shall be borne by either the interconnection customer or by PacifiCorp according to applicable electric rules and/or the terms of any executed agreements between the interconnection customer and PacifiCorp.

1.2.4 Distribution Accounts

In cases where The PacifiCorp power system reliability is threatened or where compliance with national, regional, or state reliability standards is mandatory, certain technical policies outlined in this document may apply irrespective of PacifiCorp's authority to impose the interconnection requirements.

The information in this document is subject to change. Parties interconnecting to the PacifiCorp power system should verify with their PacifiCorp representative that they have the latest version of this policy. PacifiCorp will not agree to interconnect new loads or generators unless all technical and contractual requirements are met. Copies of this document will be supplied upon request. Contact the PacifiCorp Distribution Account Manager at the address below for referrals to the PacifiCorp employee who can respond to questions concerning these policies, for interconnection coordination procedures, or for additional copies of this procedure.

Distribution Account Manager
Lloyd Center Tower
825 N.E. Multnomah Blvd. Suite 1600
Portland, Oregon 97232
(503) 813-6138

1.3 Policy for Interconnection of Generation Resources

PacifiCorp has an established policy for operating, metering, and equipment protection for generators. This policy covers these requirements for all generators wishing to interconnect to the PacifiCorp power system. Additional project-specific requirements may apply. These additional requirements may vary according to the specifications of the generator and the local configuration of the PacifiCorp power system. Additional project-specific requirements, if any, will be identified by technical studies performed by PacifiCorp prior to interconnection.

The technical studies will determine whether PacifiCorp will be required to add or modify its distribution system to interconnect the requesting party. Parties requesting interconnection are responsible for the cost of these technical studies. Interconnecting entities must also pay for, as special facilities, any additions or modifications to the PacifiCorp system needed to connect the requesting party, and for those portions of the interconnection facilities owned and maintained by PacifiCorp at the requesting party's expense. Such facilities may include metering and data processing equipment. FERC jurisdictional special facilities agreements are unique to each project but follow similar principles. Please contact the PacifiCorp Distribution Account Manager for details about the study process and additional data requirements which may apply.

1.4 Interconnection Costs

All costs incurred by PacifiCorp to accommodate the interconnection of the developer's generation to PacifiCorp's electrical system must be borne by the developer as specified by the federal PURPA law or as mandated by state tariff . These costs include, but are not limited to, the following items:

1. Engineering studies and design work necessary to permit the interconnection of the developer's generation to the PacifiCorp electrical system. This includes any preliminary preparation and estimating costs.
2. New overhead and/or underground line extensions to interconnect the developer's generation to PacifiCorp's system.
3. Conversion of single-phase lines to three-phase construction to accommodate the generation (if necessary).
4. Increasing the capacity of PacifiCorp's distribution system to accommodate the developer's generation.
5. Alterations, modifications, or additions to PacifiCorp's distribution system protection schemes necessitated by the interconnection of the developer's generation.
6. Telemetering facilities, including the cost of equipment and communication facilities as well as maintenance costs associated with these facilities.

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7. Alterations, modifications, or additions to PacifiCorp's distribution system to maintain the quality of electrical service to PacifiCorp's customers.

A detailed interconnection study report will include the details of all of these items and possibly other issues not mentioned above if the complexity of the proposed project warrents it. Contact the distribution accounts manager to discuss the process for conducting a generation interconnection study. See Appendix M for equipment lead times.

1.5 Customer-Owned Equipment Requirements

Interconnected parties are responsible for designing, installing, operating and maintaining any interconnection equipment they own. All protective devices necessary to protect the interconnected entity's facilities are the responsibility of the interconnected entity.

PacifiCorp requirements specified in this policy are designed to protect PacifiCorp facilities and maintain grid reliability pursuant to applicable reliability criteria; they are not designed to protect the facilities of interconnected generators.

Interconnected entities must satisfy: 1) the requirements in this policy, 2) applicable rules and tariffs of jurisdictional state regulatory agencies and FERC, 3) applicable policies of the Western Electricity Coordinating Council (WECC), the North American Electric Reliability Council (NERC), or their successor organizations, and 4) PacifiCorp's project-specific requirements. PacifiCorp's review and written acceptance of the interconnected entity's equipment specifications and plans shall not be construed as confirming or endorsing the interconnected entity's design, nor as warranting the equipment's safety, durability, or in any way relieving the interconnecting entity from its responsibility to meet the above requirements. PacifiCorp shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built to such specifications, nor shall PacifiCorp's acceptance be deemed an endorsement of such equipment.

1.6 General Interconnection Requirements

1.6.1 Professional Review of Drawings

All one-line diagrams and supporting material for facilities 250 KW and larger shall be stamped by a Professional Electrical Engineer in the state where the facility resides before they are submitted to PacifiCorp as part of the application. This requirement will assure that the information contained thereon is reasonable and accurate and should avoid any significant electrical engineering issues as the project proceeds to interconnection.

1.6.2 Protective Functions

The protective functions of a DG facility must further include an over/undervoltage trip function, an over/under frequency trip function, and a means for disconnecting the DG Facility from the PEDS whenever a protective function initiates a trip.

The protective functions and requirements of this document are designed to protect the PEDS and not the generating facility. The DG Facility shall be solely responsible for providing adequate protection for the DG and interconnection facilities connected to the PEDS. The protective equipment at the DG facility shall not impact the operation of other protective devices utilized on PEDS in a manner that would affect PacifiCorp's capability of providing reliable service to its customers.

1.6.3 Automatic Lockout

Protective functions shall include an automatic means to prevent the DG (Distributive Generation) facility from re-energizing a de-energized PacifiCorp Electric Distribution System (PEDS).

1.6.4 No Unintended Islanding

The DG Facility and associated protective functions shall not contribute to the formation of an unintended island.

1.6.5 Delay on Reconnections

Protective functions shall be equipped with automatic means to prevent reconnection of the generating facility with the PEDS unless the PEDS service voltage and frequency is within specified settings and is stable for at least 60 seconds.

1.6.6 Suitable Equipment

Circuit breakers or other interrupting devices located at the PCC must be certified or listed (as defined in Article 100, the definitions section of the *National Electric Code*) as suitable for their intended application. This includes being capable of interrupting the maximum available fault current expected at their location. The generating facility shall be designed so that the failure of any one device shall not potentially compromise the safety and reliability of PacifiCorp's distribution system.

1.6.7 Visible Disconnect

The DG facility shall furnish and install a manual disconnect device that has a visible break to isolate the DG Facility from the PEDS. The device must be accessible to PacifiCorp personnel and be capable of being locked in the open position. DG facilities with non-islanding inverters 1 kVA or less to be installed in the state of California are exempt from this requirement as per Rule 21.

1.6.8 Prevention of Interference

The DG facility shall not operate equipment that superimposes a voltage or current upon PacifiCorp's electric distribution system, nor which interferes with PacifiCorp operations, service to PacifiCorp customers, or PacifiCorp communication facilities. If such interference occurs, the DG facility must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by PacifiCorp. If the DG facility does not take timely corrective action, or continues to operate the equipment causing interference without restriction or limit, PacifiCorp may, without liability, disconnect the DG facility equipment from PacifiCorp's distribution system in accordance with the executed interconnection agreement. To eliminate undesirable interference caused by the operation of the generating facility, each generating unit in a generating facility shall meet the following criteria:

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Policy

1.6.8.1 Normal voltage operating range

The voltage operating range for a generating unit shall be selected as a protection function that responds to abnormal distribution system conditions and not as a voltage regulation function.

1. Small systems (11 kVA or less) – generating units connected to a generating facility with a gross nameplate capacity of 11 kVA or less shall be capable of operating within the limits normally experienced on PacifiCorp's distribution system. The operating window shall be selected in a manner that minimizes nuisance tripping and range between 106 V and 132 V (88-110 percent of nominal voltage) on a 120-volt base. Generating facilities shall cease to energize PacifiCorp lines whenever the voltage at the point of common coupling (PCC) deviates from the allowable voltage operating range.
2. Large Systems (greater than 11 kVA) – PacifiCorp may have specific operating voltage ranges for larger DGs, and may require adjustable operating voltage settings for these larger systems. In the absence of such requirements, the above principles of operating between 88 and 110 percent of the appropriate interconnection voltage should be followed.
3. Voltage Disturbances – Whenever PacifiCorp's distribution system voltage at the point of common coupling varies from normal (nominally 120 V) by predetermined amounts as set forth in Table 1, the DG facility's protective functions shall cause the generator(s) to become isolated from PacifiCorp's distribution system.

Table 1–Under/Over Voltage Trip Times

Voltage at Point of Common Coupling (assuming 120V base)	Maximum Trip Time Allowed (assuming 60 cycles per second)
< 60V	10 cycles
≥ 60V and < 106V	120 cycles
≥ 106V and ≤ 132V	Normal Operation
≥ 132V and ≤ 165V	120 cycles (30 cycles for facilities > 11kVA)
> 165V	6 cycles

1.6.8.2 Frequency

PacifiCorp's controls system frequency and the DG facility shall operate in synchronism with PacifiCorp's distribution system. Small DG facilities should have a fixed operating frequency range of 59.3 – 60.5 Hz. The DG facility must cease to energize the system in a maximum of ten cycles should PacifiCorp remain outside of the frequency limits. The purpose of the time delay is to allow the DG facility to ride through short-term disturbances to avoid excessive nuisance tripping. PacifiCorp may require adjustable operating frequency settings for DG facilities larger than 11 kVA in order to assist the system during serious capacity shortages.

1.6.8.3 Direct Current Injection

DG facilities should not inject direct current greater than 0.5 percent of rated output current into PacifiCorp's distribution system under either normal or abnormal operating conditions.

1.6.8.4 Power Factor

Each generating unit in a DG facility shall be capable of operating at some point within a range of a power factor of 0.95 (either leading or lagging). Operation outside this range is acceptable provided the reactive power of the DG facility is used to meet the reactive power needs of on-site loads or that reactive power is otherwise provided under tariff by PacifiCorp.

1.6.8.5 Voltage Fluctuation Limits

The interconnection customer should expect a normal operating voltage range of +/- 5 percent from nominal. The owner/developer should contact PacifiCorp to determine the normal operating voltage at their point of interconnection The plant should be capable of start-up whenever the voltage at the point of interconnection is within this range. If the auxiliary equipment within the generator cannot operate within the above range, the generator will need to provide regulation equipment to limit the station service voltage-level excursions. During system contingency or emergency operation, operating voltages may vary up to ± 10 percent from nominal.

1.6.8.6 Harmonic Limits

All interconnection customers shall comply with the voltage and current harmonic limits specified in IEEE Standard 519, *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

The harmonic content of the voltage and current waveforms in the PacifiCorp system must be restricted to levels which do not cause interference or equipment operating problems for PacifiCorp or its customers.

Any harmonic problems shall be handled on a case–by-case basis. A generation facility causing harmonic interference is considered by PacifiCorp to be a serious interference with service and is subject to disconnection from the PacifiCorp system until the condition has been corrected. If the cause of the problem is traceable to the interconnection customer's facilities, all costs associated with determining and correcting problems shall be at the customer's expense.

Many methods may be used to restrict harmonics. The preferred method is to install a transformer with at least one delta connection between the generator and the PacifiCorp system. This method significantly limits the amount of voltage and current harmonics entering the PacifiCorp system. Generation system configuration with a star-grounded generator and a two-winding (both star-grounded) transformer shall not be allowed.

1.6.8.7 Voltage Flicker Limits

All interconnection customers shall adhere to PacifiCorp’s policy on voltage fluctuation and light flicker at the PCC with PacifiCorp. This issue primarily focuses on wind turbine-based generation but may be applicable to other forms of generation. Voltage fluctuation is more pronounced with one or two wind turbines installed on distribution circuits where the X-to-R ratio of the line is high. PacifiCorp's policy is available in the Engineering Handbook, Section 1C.5.1, which can be found on the PacifiCorp web site. This policy is based on IEEE Standard 1453 - 2004, *Voltage Flicker*. It is the generator owner/developer's responsibility to determine the expected Pst flicker values caused by the addition of their generator(s). It will also be the owner/developer's responsibility to bring the Pst flicker level into compliance with PacifiCorp's policy at the developer's cost should the values exceed PacifiCorp's policy limits at any time during the life of operation of the facility on PacifiCorp's electrical system. This could occur at the time of installation or a later date. The developer must allow for reasonable corrective contingencies if system operations or circuit modifications alter the circuit's electrical characteristics.

1.7 Technology Specific Policy Requirements

1.7.1 Three-Phase Synchronous Generating Facilities

For three-phase generating facilities, the generating facility circuit breakers shall be three-phase devices with electronic or electromechanical control. The DG facility shall be responsible for properly synchronizing its generating facility with PacifiCorp's distribution system by means of either a manual or automatic synchronizing function. Automatic synchronizing is required for all synchronous generating units, which have a short-circuit contribution ratio (SCCR) exceeding 0.05. A generating unit whose SCCR exceeds 0.05 shall be equipped with protective functions suitable for detecting loss of synchronism and rapidly disconnecting the generating facility from PacifiCorp's system. Unless otherwise agreed upon by the producer and PacifiCorp, synchronous generating units shall automatically regulate power factor, not voltage, while operating in parallel with PacifiCorp's distribution system. Power system stabilization is specifically not required for generating facilities under 10 MW gross nameplate capacity. Synchronization means that at the time of connection, the frequency difference shall be less than 0.2 Hz, the voltage difference shall be less than ten percent, and the phase angle difference shall be less than ten degrees.

1.7.2 Induction Generators

Induction generator generating units do not require separate synchronizing equipment. Starting or rapid-load fluctuations on induction generators can adversely impact PacifiCorp's distribution system voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferroresonance. When these counter measures (e.g., additional capacitors) are installed on the producer's side of the point of common coupling, PacifiCorp must review these measures. Additional equipment may be required to resolve this problem as determined in an interconnections study.

See Appendix Q for specific information on wind turbine installations on distribution systems.

1.7.3 Inverter Systems

Utility-interactive inverters do not require separate synchronizing equipment. Non-utility-interactive or "stand-alone" inverters shall not be used for parallel operation with PacifiCorp's distribution system. Inverters shall be UL 1741 certified. No inverters will be permitted to interconnect with PacifiCorp's electrical system that are not certified; non-certified interconnections will be disconnected until they are brought into compliance with this policy.

2 OWNERSHIP POLICY

2.1 Ownership and Operation of Interconnection Facilities and Equipment

For new generation facilities, PacifiCorp shall not own, operate, nor maintain any of the interconnection facilities downstream electrically from PacifiCorp's meter. It will be assumed that this equipment is owned, operated, and maintained by the interconnection customer. This equipment includes the transformer, breaker, and relay and protection devices. Any recloser on PacifiCorp facilities shall be owned, operated, and maintained by PacifiCorp. If a recloser is installed or an existing recloser is modified due to the introduction of a generation facility on a distribution circuit, all costs (purchase of device, installation, operation, and maintenance) shall be borne by the interconnection customer as specified in the interconnection and construction agreements.

For new generation facilities, PacifiCorp will own, operate, maintain, test, and install all communication equipment including the circuit from PacifiCorp's facilities to the interconnection customer's facilities if the circuit is a technology other than land line wire. Land line-wire circuits are to be owned/leased, operated, and maintained by an entity other than PacifiCorp (either the interconnection customer or a telephone company). The protective relay(s) and all other equipment downstream from the PCC will be owned, installed, and maintained by the developer.

For existing generation facilities where circuit-loading changes mandate transfer trip, PacifiCorp will own, operate, maintain, test, and install all communication equipment necessary to perform this function as per the language of the interconnection agreement if addressed. The developer will own (upgrade if necessary) and maintain the same equipment originally installed downstream from the PCC (i.e. relay(s), breaker(s), etc.).

See Appendix C for equipment configuration and ownership of a typical distribution generation project.

2.2 Applicant Construction of PacifiCorp Facilities

When it is mutually agreed by PacifiCorp and the interconnection customer that the interconnection customer shall design and build PacifiCorp facilities, the interconnection customer shall provide PacifiCorp with design drawings prior to the start of construction and shall continue to provide PacifiCorp with the latest revisions sent to the contractor for construction. Within 30 days of the completion of construction, the interconnection customer shall provide PacifiCorp with a complete set of design drawings revised to reflect any as-builts. In addition, the interconnect customer shall be responsible for obtaining SAP numbers and equipment memorandum forms from PacifiCorp and completing the equipment memorandums for all major equipment identified by PacifiCorp as requiring setup in SAP to provide the means for scheduling future maintenance. The interconnection customer shall provide PacifiCorp with the completed equipment memorandums upon the installation of the major equipment for which they are required.

2.3 Specification/Approval of Interconnection Customer's Facilities and Equipment

PacifiCorp retains the right to electrically disconnect any generation facility that does not acquire and/or retain PacifiCorp-approved interconnection equipment of the following types: relays, disconnect devices, transformers, RTUs, and communication equipment. The specifications for this equipment is contained in this policy document. It shall be the responsibility of the interconnection customer to comply with this requirement and submit to PacifiCorp documentation signed off by a licensed Professional Electrical Engineer for the state in which the facility resides. The PE signature shall indicate compliance with the applicable interconnection agreement. PacifiCorp will issue written notice to the interconnection customer upon knowledge of a breach in this regard and give the developer a reasonable time to correct the issues raised in the letter. Failure to comply with this notice will result in electrical disconnection as described in the disconnection notice.

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Policy

3 TELECOMMUNICATION REQUIREMENTS FOR GENERATION INTERCONNECTION

3.1 Application

Before a new generation facility is to be connected to the PacifiCorp power system, PacifiCorp will specify the metering, protection, supervisory control and data acquisition (SCADA), telemetering, and telecommunications channels that will be required. Due to the highly specialized and critical nature of the protection, metering, SCADA, and telemetering equipment, PacifiCorp requires that all such equipment be owned, installed, and maintained by PacifiCorp at the generation facility's expense. Also, due to the critical protection requirements for the interconnection of the generation facility to PacifiCorp's distribution/transmission system and the varied PacifiCorp internal telecommunications systems that may be available for the specific generation facility, the telecommunication channels described below must be defined on a case-by-case basis.

3.2 General Requirements

The generation facility will be responsible for acquiring the communication lines from the local telephone company or multiple telephone companies as required to meet the telecommunications required of the new generation facility with the exception that if tele-protected (requires communications channel) relay channels are needed, PacifiCorp will provide them at the cost of the generation facility. Due to the critical nature of the protection, metering, SCADA, and telemetering requirements, PacifiCorp will define the technical requirements and may provide, at its option, all or portions of the telecommunication channels on its existing internal telecommunication network at the cost of the generation facility.

3.3 Telecommunication Circuit Requirements

3.3.1 New Generation Facilities < 3,000 kW with no Teleprotection Requirement

3.3.1.1 Business Telephone Line

A business telephone line at the location of the interconnect point metering equipment is required for remote revenue-metering reading and maintenance work.

3.3.2 New Generation Facilities ≥ 3,000 kW or New Generation Facilities < 3,000 kW with Teleprotection Requirement

3.3.2.1 Remote-Metering Business Telephone Line

A business telephone line is required at the location of the interconnect point metering equipment for remote revenue-metering reading. The generation entity must provide landline telephone access, if possible. If local telco facilities are not available, other options for providing dial-up access to the meter will be considered.

3.3.2.2 Dispatch Business Telephone Line

A business telephone line is required so that operating instructions from PacifiCorp may be given to the designated operator of the generation facility equipment. Unless other arrangements are made to use PacifiCorp's

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Policy

existing telecommunications network, the generation entity must provide a local telephone.

3.3.2.3 Protective Relay Remote Access Business Telephone Line

A business telephone line is required at the location of the protective relay equipment for remote maintenance of the protective relay equipment. Unless other arrangements are made to use PacifiCorp's existing telecommunications network, the Generation Entity must provide a local telephone.

3.3.2.4 Protective Relays

PacifiCorp will determine if non-pilot protective relays will be adequate for emergency tripping of the generation facility and/or protection of the distribution system or if tele-protected type protection equipment is required. PacifiCorp will design and provide telecommunications channels suitable for the protective relay package required at the cost of the generation facility. Local telephone company leased lines are not acceptable for protective relay channels. Telecommunication channels for protective relay equipment may consist of a fiber optic system, power line carrier, microwave radio, or a combination of these systems.

3.3.2.5 SCADA Remote Terminal Unit (RTU)

Real-time data and/or control via a SCADA RTU is be communicated to PacifiCorp's Control Center. Unless other arrangements are made to use PacifiCorp's existing telecommunications network, the generation entity must provide a local telephone company VG36, Class B, Type 3, 4-wire, full-duplex communication line from the generation facility to PacifiCorp's Control Center. PacifiCorp will specify the location where the communication line will terminate. Telecommunication channels for SCADA RTU equipment, when using PacifiCorp's telecommunications network, may consist of fiber optic system, microwave radio, other radio system, or a combination of these systems.

3.3.2.6 Analog Telemetering

Analog telemetering of the total generation facility's kW output to PacifiCorp's alternate control sites (Medford, Oregon; Yakima, Washington; Goshen, Idaho; or Sigurd, Utah) is required as an interim solution per NERC Standard EOP-008-0, *Plans for Loss of Control Center Functionality*. Unless other arrangements are made to use PacifiCorp's existing telecommunications network, the generation entity must provide a local telephone company VG36, Class B, Type 3, 2-wire, communication line from the generation facility to PacifiCorp's alternate control site. PacifiCorp will specify the location of the closest alternate control site where the communication line will terminate. Telecommunications channel for analog telemetering equipment, when using PacifiCorp's telecommunications network, may consist of fiber optic system, power line carrier, microwave radio, or a combination of these systems. The analog telemetering channel may use the same telecommunications system as the SCADA RTU channel providing it is not routed through PacifiCorp's Control Centers.

3.4 Telephone Company Line Treatment Equipment

Proper cable and protection equipment may be required at substations and other high-voltage electric facilities for expected ground potential rise (GPR). The GPR testing required to determine the required telephone line protection may be performed by PacifiCorp at the cost of the generation facility or may be performed by generation facility itself. The calculated GPR value will determine what grade of telephone-cable high-voltage protection equipment is required, as well as the distance from the generation facility at which the telco pedestal shall be located. The local telephone company must be informed in advance (up to six months) so outside plant facilities can be engineered to serve the generation facility location. Some independent telephone companies are not tariffed to provide protection equipment. In this case, the generation facility will be required to purchase and install the necessary telephone line protection equipment.

3.5 Communications Procedures

3.5.1 Normal Operating Conditions

The interconnection customer shall provide to PacifiCorp the information necessary to communicate with the equipment and/or personnel at the generation facility during routine operating conditions. This information shall be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

3.5.2 Emergency Operating Conditions

The interconnection customer shall provide to PacifiCorp the information necessary to communicate with the equipment and/or personnel at the generation facility during the loss of the primary communication medium. This would be considered the emergency operating condition. This information is also to be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

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4 METERING POLICY FOR INTERCONNECTION CUSTOMERS

4.1 General

The purpose of this section is to assist a generation facility in accommodating PacifiCorp metering for the measurement of electricity supplied to the PacifiCorp system. This section is applicable only to those providing power to the PacifiCorp power system. The general requirements are similar to the general requirements for metering the supply of electrical service by PacifiCorp.

Usually, when a generator is installed with the intent of providing power to the PacifiCorp power system, electric service to the auxiliary load associated with the generation plant is also needed. As such, power may flow into or out of the plant at different times. Deliveries to and from the plant (bi-directional metering) must be separately recorded and treated as separate transactions under PacifiCorp's tariffs. All meters and instrument transformers shall be provided, owned, and maintained by PacifiCorp at the power producer's expense

At the Power producer's request, PacifiCorp will install net generation metering which may be used to satisfy a qualifying facility's status as outlined in Code of Federal Regulations 18 CFR 292, *Public Utility Regulatory Policies*.

4.2 Basic Metering Policy for Generators

4.2.1 Metering Requirements

The standard PacifiCorp meter used for all generation interchange projects is the Landis and Gyr, Maxsys 2510 meter. The meter will be programmed with a standardized PacifiCorp internal program that will include bidirectional kWh and kvarh energy and kW and kvar sliding 15-minute demand quantities, with instantaneous MW Mvar data. The meters will be programmed to record 15-minute interval profile demand that includes bidirectional kWh and kvarh and per-phase volt hour demand interval recording. The kWh digital or analog accumulator data will be read hourly and compiled for the monthly kWh interchange report.

Additional quantities can be added if necessary to the basic program.

Metering data collected will include working meter register reads, monthly register freeze reads, and 15-minute demand interval profile data. The meter will perform a self-freeze read at midnight each month. The meters shall be compatible with the PacifiCorp MV-90™ system and shall be interrogated daily or whenever necessary for maintenance purposes. For 3 MW and above installations, the metering design package will include two revenue-quality meters, a test switch, and all data inputs and outputs terminated at a utility interposition block. One meter will be designated a primary meter and shall be used for EMS data that includes bidirectional kWh quantities and instantaneous MW Mvar data. The second or backup meter will be used for telemetry MW data sent to the PacifiCorp Alternate Control Center.

All meters will include both analog and digital output boards following current PacifiCorp specifications. The metering design will include a test switch with all data inputs and outputs terminated at a utility interposition block.

The final metering design requirements including hardware I/O and software specifications will be written into the specific project's scoping documentation. Requests from foreign utilities for digital or analog metering outputs must be made prior to final design. A second or backup meter will be added when needed or if there are additional metering outputs required beyond what is possible from the primary meter.

4.2.2 Metering Location

All generation connections require a policy interchange metering system design package for PacifiCorp billing and/or scheduling processes. PacifiCorp will own and maintain the revenue metering at generation interchange metering sites. When requested, PacifiCorp will supply outside parties with the design details of the policy metering system. The approved policy PacifiCorp metering package provides a three-phase four-wire three-element grounded installation. Un-grounded three-wire metering systems are not approved.

Metering must be installed at the point of interconnection with the PacifiCorp power system. PacifiCorp metering is required at the point of interconnect for all interconnection customers. If it is not possible to install metering at the physical point of interconnect, PacifiCorp will require that line losses be calculated. The calculated loss algorithm may be additive or subtractive depending upon current flow through the meter. The calculated loss algorithm will be programmed within the meter(s) firmware to adjust the registers, load profile, and any digital or analog outputs. PacifiCorp requires that any applicable line loss compensation be performed in the meter, rather than calculated in the billing system.

4.2.3 Metering Structures

Unless other arrangements are made the Power producer shall provide, install, own, and maintain all mounting structures, conduits, meter sockets, meter socket enclosures, metering transformer cabinets, and switchboard service sections approved by PacifiCorp. Prior to installation of metering equipment, PacifiCorp must receive and approve meter location and enclosure dimensional drawings. Other requirements vary by the amount of power delivered to PacifiCorp. For applications below 600 V, the distance between the meter and the revenue-metering transformers must not exceed 50 feet. The intent is to not exceed the metering-transformer burdens. PacifiCorp must approve any variance from this general rule. Metering structures typically consist of primary ground-mounted, metal-clad switchgear. Physical space restrictions as well as local codes and ordinances may require variation from the above policy; in such cases Good Utility Practice shall prevail.

4.2.4 Metering Disconnects

High-side metering shall have a minimum of two gang-operated, lockable disconnect devices to facilitate establishing a visual open. Disconnect devices are necessary at the following locations:

1. At the point of interconnection with PacifiCorp (this switch is PacifiCorp-operated).

2. Between the generator side of PacifiCorp's metering and the interconnection customer's electrical facility (this switch is owned and operated by the interconnection customer).
3. If the generation facility is selling power to PacifiCorp on a surplus sale basis, a separate disconnect device (generator or host-site-owned and -operated) is required on the metering side of the load. Refer to Figure 1 for typical interconnections. Distribution pole-top metering requires only one switch located on the load side of the metering.

4.3 Metering Policy for Existing Generators

The following sections describe the detailed requirements for metering electricity supplied by generators connected to the PacifiCorp system as per the following classifications and depending upon the contractual arrangements.

Surplus-Sale Operation: Meters shall be required to measure both the net generator output and the surplus generation delivered to the PacifiCorp system.

Net-Sale Operation: Meters shall be required at the point of interconnection.

No-Sale Operation: Metering will not be required for the measurement of power delivered into the PacifiCorp system, except that load-profile and net-generator profile metering may be required for standby service.

Wheeling Service: Wheeling Service under certain existing agreements on the PacifiCorp system require two sets of revenue-metering equipment which may be totalized to accommodate various line and switch configurations. Import metering is required to the point of import (receipt) to (on) the PacifiCorp system. Export metering is required at the point of export (delivery) from (off) the PacifiCorp system.

4.4 Interchange Metering System 600 V – 34.5kV

All generation connections require an interchange metering system design package for PacifiCorp billing and/or scheduling processes. PacifiCorp will own and maintain the revenue metering at generation interchange metering sites. When requested, PacifiCorp will supply outside parties with the design details of the metering system. The approved policy PacifiCorp metering package provides a three-phase four-wire three-element grounded installation. Un-grounded three wire metering systems are not approved.

4.5 Backup metering

For 3 MW and above facilities a backup meter is required to be installed and shall programmed and tested in an identical fashion as the primary meter. The purpose for the backup meter is to provide metering data for telemetry and to be an alternate source of data in the event of a failure to the primary meter.

4.6 Metering Communication Policy

All interchange metering will require a dedicated voice-grade data phone line for use with the PacifiCorp MV-90 meter data collection system. It will be the responsibility of the generation customer to supply both the land line and any communication protection devices necessary for PacifiCorp to remotely interrogate the meter.

For installations with limited land lines it is acceptable for a Teltone Gauntlet Gateway line switch to be used for adding data-phone connections and addressing land line communications.

4.7 General Installation Applications below 600 V

4.7.1 Self-Contained Metering (120 – 480 V)

Single phase metering of 400 amps or less and three phase metering of 200 amps or less:

All meter sockets for self-contained installations shall be furnished, installed, and wired by the generation customer. Required socket types are summarized in the PacifiCorp Electric Service Requirements (ESR) manual.

4.7.2 Single-Phase Metering > 400 amps and Three-Phase Metering > 200 amps

Current transformer (CT) metering is required when a three-phase service exceeds 200 amps or when a single-phase service exceeds 400 amps. The generation customer shall provide and install a EUSERC-approved meter socket enclosure and a current-transformer cabinet. Approved meter socket and cabinets shall be in compliance with the PacifiCorp ESR.

4.8 Primary Installation Applications (600 V – 34.5 kV)

4.8.1 Underground-Enclosed Metering

For underground primary metering customers shall meet the PacifiCorp requirements for a primary metering station as described in the ESR. The metering station shall comply with PacifiCorp Material Specification ZM 003, *Primary Metering Enclosure, Padmount*.

4.8.2 Switchgear- or Substation-Enclosed Metering

Customers shall meet the requirements of EUSERC, Section 400 whenever switchgear enclosures are required to meter medium-voltage interchange services.

The customer shall provide all necessary hardware per EUSERC, Section 400. A clear work space 78” high, 36” wide, and 48” deep in front of distribution metering equipment (per current NEC requirements) is required. A concrete mounting pad at least 4” thick is required for the switchgear metering enclosure.

The metering instrument transformers will be specified by PacifiCorp and shall be provided and installed by the manufacture of the switchgear. The meter, test switch, and any specialized hardware will be specified, ordered, and installed by PacifiCorp.

4.8.3 Primary Pole-Mounted

Customers shall install metering equipment according to PacifiCorp’s Construction Metering Standards, Section DM.

The metering instrument transformers will be specified by PacifiCorp. The cluster-mounted primary metering, including instrument transformers, meter, test switch, and any specialized hardware will be specified, ordered, and installed by PacifiCorp.

4.8.4 Indoor Panel Applications

When meter panels are required to mount meters and metering hardware, PacifiCorp will specify, order, and install all revenue panels. The meter panels will be 12" wide by 90" high and shall require a clear work space 36" wide, 90" high, and 48" deep in front and to the rear of the panel.

4.9 Outdoor Meter Enclosure Applications

When it is necessary to mount meters and metering hardware in outdoor locations, PacifiCorp will specify and order the metering box enclosure. The enclosure will be mounted and installed by the facility owner's contractor. When outside meter enclosures are used, they typically serve both as the junction box and meter socket enclosure. The meter enclosure box will be 3R-rated by the National Equipment Manufacturer's Association (NEMA), and shall have sealing provisions.

4.10 Sealable Junction Box

The junction box provides a means of terminating the utility's service conductors when they are required (for instance, on indoor-panel applications). The use of this junction box shall be coordinated with PacifiCorp prior to installation. The junction box will be NEMA 3R-rated, and shall have sealing provisions.

4.11 Secondary Leads and Termination

All metering secondary leads or cable (with the exception of prefabricated switchgear equipment) will be provided by PacifiCorp. The secondary leads will conform to PacifiCorp policies and color-code requirements. Lead terminations may be done by manufacturer or contractor, but all will be inspected and approved by PacifiCorp.

4.12 Conduit Substation > 600 volts

For running secondary metering leads between the connections at the meters and the instrument transformers located in the substation yard, the generation customer is to provide a minimum size of 3-inch conduit. When the distance between the revenue instrument transformers and meter panel is greater than 250 feet, it may be necessary to increase the conduit size to accommodate paralleled CT metering secondaries to reduce the burden to the current transformers. PacifiCorp shall procure all conductors and the generation customer shall install meter-wiring cable from the transformers to the revenue-metering panel located in the substation. The conduit shall be PVC, rigid steel, or IMC and must be installed with long-radius sweeps. The customer contractor is responsible for proper installation practices.

4.12.1 Requirements for a Meter within Four to 12 Inches of CT Compartment

1. 1" minimum conduit of rigid steel or IMC.
2. Proper fittings and bushings to protect metering conductors.
3. Schedule 40 PVC/ EMT may be allowed when a bonding lug is provided in both the CT cabinet and meter base.

4.12.2 Requirements for a Meter and CT Cabinet > 12 inches but < 50 feet apart

1. 1.25" minimum conduit of PVC, rigid stell, or IMC.
2. Conduit runs may not have more than three bends totaling 270 degrees. No single bend greater than 90 degrees is allowed .

3. Pull lines are required in all conduit.
4. Removable conduit fittings shall have sealing provisions. (LB connectors are not allowed outside the enclosure without prior written approval from PacifiCorp).

4.12.3 Requirements for a Meter and CT cabinet > 50 Feet Apart

1. 3" minimum conduit of PVC, rigid steel, or IMC.
2. Conduit runs may not have more than three bends totaling 270 degrees. No single bend greater than 90 degrees is allowed.
3. Pull lines are required in all conduit.
4. Removable conduit fittings shall have sealing provisions. (LB connectors are not allowed outside the enclosure without prior written approval from PacifiCorp).

4.13 Meter Testing

PacifiCorp and the generation customer agree that certification of meter system accuracy be done at least biannually or as specifically agreed upon in the interchange agreement. PacifiCorp shall give all interested parties notification of at least two weeks for the impending test. A copy of the test results shall be kept on file and shall be made available for review.

4.14 Instrument Transformers

Voltage and current instrument transformers are required to be 0.3 percent metering accuracy class for both ratio error and phase-angle error over the burden range of the installed metering circuit. Instrument transformers shall be stand-alone, located on the line at the delivery point such that the metering is not interrupted during possible switching configurations at the delivery point unless the metering is being removed for service. Paralleling CTs and internal CTs located inside breakers and power transformers for the purpose of revenue metering will not be permitted.

4.15 Loss Compensation

PacifiCorp may require that distribution system losses such as those in lines and transformers be accounted for in the revenue metering process. PacifiCorp requires that any applicable loss compensation be performed in the meter, rather than calculated in the billing system. PacifiCorp engineering will calculate the meter firmware algorithms to accommodate the transformer and/or line loss factors applicable to each site.

4.16 Station Service Power

Depending upon its electrical source and electrical location, the station service power for connecting substation facilities may also require revenue metering. It may or may not be necessary to meter station service var hours. The other requirements of this section apply to station service metering.

4.17 Instrument Transformer Verification

At least once during the life of the transformer, a documented verification of instrument transformer ratios shall be performed. This requires measurement of primary current simultaneously with secondary current to determine actual ratio to within ten percent of marked nameplate ratio. Transformer turns ratio (TTR) on voltage transformers or CT tester check shall substitute if in-service primary measuring equipment is unavailable. The objective is to ensure that the instrument transformer ratios are documented and are connected to known taps under known burden conditions. This test shall be performed during a scheduled bi-annual test if there is no record of a verification being performed and when instrument transformers are replaced.

4.17.1 Metering Generation Loads

When a generation entity sells power to PacifiCorp, electric service to the auxiliary load associated with the generator plant is also needed. Because deliveries to and from the plant must be separately recorded and treated as separate transactions under PacifiCorp's tariffs, multifunction revenue metering will be required in most cases.

For generators 100 kW or less (connected to PacifiCorp's secondary service voltage), where non-utility generators (NUG) (i.e., emergency generators, peak shaving generators, etc.) or portable plug-ins (generators not permanently wired to the outlet) are connected via an electrical outlet or automatically connected via an automatic transfer switch, a visible disconnect shall be required. A visible disconnect can be a disconnect knife switch or a combination of a manual disconnect circuit breaker, built-in switch, and red-light indicators. These fail-safe indicators shall be visible at all times and shall have at a mimumum one red light bulb per conductor indicating energized/de-energized conditions of the utility and generator source conductors on the line side of the main disconnect or circuit breaker.

4.18 Telemetering Policy for Generator Monitoring

4.18.1 For New Generation Facilities ≥ 3 MW

For generation facilities 3 MW or greater, the following real-time data is to be telemetered to PacifiCorp's Control Center for each generating unit over 3,000 kW in size:

- kW
- kvar
- status (on-line or off-line)

A telemetering circuit to the PacifiCorp Control Center is also required. Control of the breakers at the interconnection switching station may be required, depending on configuration. A minimum number of alarms to be transmitted include the following:

- breaker trip
- transfer trip receive (if applicable)
- channel/equipment fail

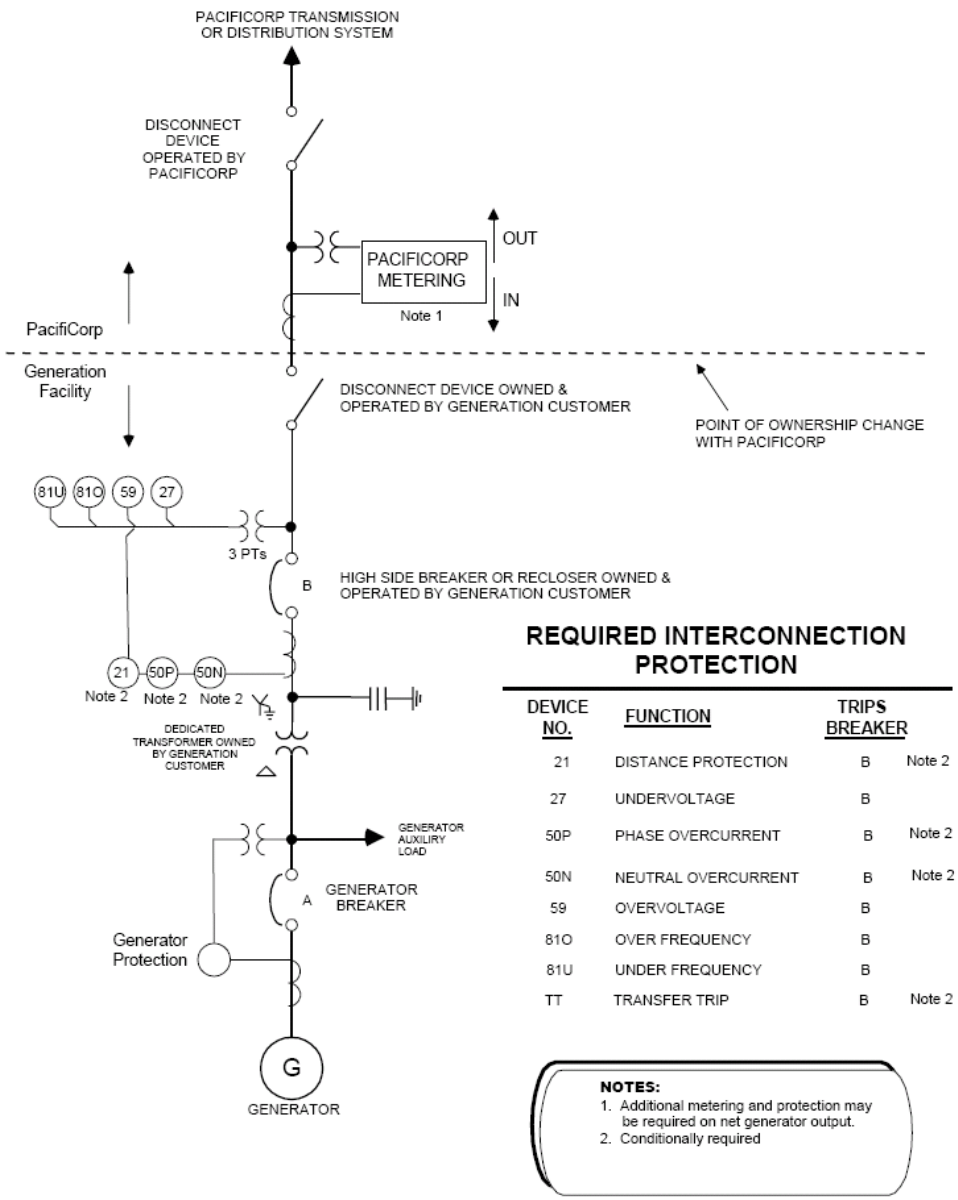
Unless other arrangements are made, the interconnection customer must provide communication lines with the following minimum specifications: VG36, Class B, Type 3, four-wire, full duplex (1200 baud).

Telemetering equipment (usually an RTU and an analog tone telemeter) shall be located in the metering enclosure. At the entity's expense, PacifiCorp will supply telemetering equipment at the interconnection customer's site, at PacifiCorp's Control Center, and at the designated PacifiCorp alternate control site.

4.18.2 For Generation Facilities < 3,000 kW

PacifiCorp will have telemetry for generators of less than 3,000 kW that were installed prior to the January 2007 revision of this document. No new facilities less than 3,000 kW proposed for interconnection after January 2007 will be required to install telemetry. PacifiCorp management reserves the right to alter this policy at any time. Please check with the PacifiCorp Distribution Account Manager to determine the most up–to-date policy.

Figure 1–Typical Metering Installation for Protection and Metering



REQUIRED INTERCONNECTION PROTECTION

DEVICE NO.	FUNCTION	TRIPS BREAKER	
21	DISTANCE PROTECTION	B	Note 2
27	UNDERVOLTAGE	B	
50P	PHASE OVERCURRENT	B	Note 2
50N	NEUTRAL OVERCURRENT	B	Note 2
59	OVERVOLTAGE	B	
81O	OVER FREQUENCY	B	
81U	UNDER FREQUENCY	B	
TT	TRANSFER TRIP	B	Note 2

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5 RELAY PROTECTION AND CONTROL POLICY FOR INTERCONNECTION CUSTOMERS

This section specifies the protective and control requirements for interconnection requests from interconnection customers to PacifiCorp's power system.

5.1 Applicability

The applicable protective policies of this section apply to all generators interconnecting to any portion of the PacifiCorp power system. These policies, which govern the design, construction, inspection, and testing of protective devices, have been developed by PacifiCorp to be consistent with applicable reliability criteria and policies.

5.2 Protective Relay Policy

An important objective in the interconnection of facilities to the PacifiCorp system is minimizing the potential hazard to life and property. A primary safety requirement is the ability to disconnect immediately when a fault is detected. Generating entities desiring interconnection with the PacifiCorp power system must comply with all applicable jurisdictional state regulatory agency rules in this regard.

The protection equipment for a generation facility must protect against faults within that facility and faults on the PacifiCorp system. As a general rule, a generation facility must also trip off-line (disconnect from the PacifiCorp system automatically) when PacifiCorp's power is disconnected from the line into which the unit is generating.

The protection equipment at a generation facility is divided into two categories: generator protection and interconnection protection. Generator protection is primarily concerned with detecting abnormal conditions within the generation facility. Interconnection protection is concerned with protecting other customers from abnormal conditions caused by the generation facility. It is imperative that a generation facility disconnect from the PacifiCorp power system before the feeder to which the generation facility is connected. Figure 1 is a basic diagram of a typical interconnection.

In view of these objectives, PacifiCorp requires line-protective equipment to either 1) automatically clear a fault and restore power, or 2) isolate only the faulted section so that any outages affect a minimum number of customers.

Due to the high-energy capacity of the PacifiCorp distribution system, high-speed fault clearing may be required to minimize equipment damage and potential impact to system stability. The requirement of high-speed fault clearing will be determined by PacifiCorp on a case–by-case basis. To achieve these results, relays and protective devices are needed. The requirements are outlined in the following pages. Some protection requirements can be standardized, however most line relaying depends on generator size and type, number of generators, line characteristics (i.e., voltage, impedance, ampacity), and the existing protection equipment connected to the PacifiCorp system.

PacifiCorp's minimum protection requirements are designed and intended to protect the PacifiCorp system only. As a general rule, neither party should depend on the other for the protection of its own equipment. Additional protective relays are typically needed to protect the interconnection customer's facility adequately. It is the interconnection customer's responsibility to protect its own system and equipment.

PacifiCorp requires that the developer hire a PE licensed in electrical engineering to review the electrical design of the proposed generation facility to ensure that it will be adequately protected.

The interconnection customer must provide PacifiCorp test reports for all relays outlined in Tables 1 and 2 before PacifiCorp will allow the facility to parallel. Refer to Section 8.10.6 for information regarding pre-parallel inspections. Every four years thereafter, the interconnection customer must submit written proof, by testing or other means acceptable to PacifiCorp, that the relays are operable and within calibration. PacifiCorp will not test the entity's equipment, but may witness the testing performed by a qualified testing firm retained by the entity. On-site power (typically 120 V) is required for the test equipment. Circuit breakers must be tested at least every eight years after the pre-parallel inspection. It is also in the interconnection customer's best interest to make sure all of its protective equipment is operating properly, since significant equipment damage and liability can result from failures of the entity's protective equipment.

5.3 Reliability and Redundancy

The interconnection customer shall design the protection system with sufficient redundancy or relay coordination that the failure of any one component will still permit the interconnection customer's facility to be isolated from the PacifiCorp system under a fault condition. Multi-function three-phase protective relays must have redundant relay(s) for back-up unless otherwise agreed to by PacifiCorp. The required breakers must be trip tested by the interconnection customer at least once a year.

5.4 Relay Protection Elements

The following is a desciption of the relay elements shown in Figure 1.

21 – Distance relay is a relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value. This type of relay may be required when the Generation Entity is connecting two (2) or more generators to The PacifiCorp power system. This determination is made during the System Impact Study and is based on minimum peak loading of the feeder tow which the Generator Entity will connect.

27 – Undervoltage relay is a relay that operates when its input voltage is less than a predetermined value. PacifiCorp requires three (3) undervoltage elements with time delay. Settings will be determined during the System Impact Study.

50P – Phase instantaneous overcurrent relay is a relay that functions instantaneously on an excessive value of phase current. The requirement for this element is based on minimum peak loading of the feeder tow which the Generator Entity will connect.

59N – 3V0 overvoltage relay is a relay that functions instantaneously on an excessive value of 3V0 voltage. This element utilizes the second coil of the potential transformer wired in a broken delta. Settings will be determined during the System Impact Study.

59 – Overvoltage relay is a relay that operates when its input voltage is higher than a predetermined value. This element is utilizes a current transformer between the transformer and the high side breaker. Settings will be determined during the System Impact Study.

81O – Overfrequency relay is a relay that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds a predetermined value. PacifiCorp requires three (3) overfrequency elements with time delay. Settings will be determined during the System Impact Study and are based on radial or non-radial connections.

81U – Underfrequency relay is a relay that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency is less than a predetermined value. PacifiCorp requires three (3) underfrequency elements with time delay. Settings will be determined during the System Impact Study and are based on radial or non-radial connections.

TT – Transfer Trip is a scheme that operates based on a remote signal. Transfer trip could utilize, fiber, leased line, microwave, etc. as determined by PacifiCorp. Transfer trip may be required depending on PacifiCorp circuit configuration and loading, as determined by PacifiCorp. Typically, transfer trip shall be required if PacifiCorp determines that a generation facility cannot detect and trip on PacifiCorp end-of-line faults within an acceptable time frame or if the generation facility may be capable of keeping a PacifiCorp line energized with the PacifiCorp source disconnected. It may be in the generation facility's best interest to purchase relays capable of communications in the event transfer trip is later required.

5.4.1 Relays Approved by PacifiCorp

PacifiCorp is familiar with all major utility-grade relay manufacturers. Below is a listing of major vendors; it is intended to be a sample and not an exhaustive listing.

- ABB
- Areva
- Beckwith
- Basler
- Cooper
- GE
- Schweitzer
- Siemens

PacifiCorp will accept any utility-grade relay or combination of relays from this list provided that all required relay elements are fulfilled.

PacifiCorp approval does not indicate the quality or reliability of a product or service, and endorsements or warranties shall be implied.

See Appendix B for equipment configuration and ownership of a transfer trip scheme.

5.5 Line Protection

Many factors are considered when determining the protective relaying requirements needed by interconnection customer to protect PacifiCorp facilities and the customers' equipment. Some of these factors are: the zone of protection, location of connection to the PacifiCorp system, location of customers relative to the location of connection, and the type of protection system used on the PacifiCorp power system.

The zone of protection refers to the area in PacifiCorp's system where the interconnection customer facility must provide fault protection. When a fault occurs, the interconnection customer's protective relays shall cause the isolation of the interconnection customer's facilities from PacifiCorp's or the interconnection customer's system. If there are any PacifiCorp customers connected to the system in the zone of protection, the protection system shall be designed such that the service to those customers is not diminished by the addition of the interconnection customer's facilities. This includes the amount of delay in automatic testing of the zone of protection by PacifiCorp's equipment following a fault.

There are in many cases options for providing the protective relay system for the zone of protection. These options will effect the up-front cost and the reliability of the interconnection customer's facilities. The use of pilot relaying or direct transfer trip communication may increase the cost to the interconnection customer, however the use of these systems will limit the number of times the facility is forced offline to protect PacifiCorp's system. This is especially true when a PacifiCorp customer is connected to the system in the zone of protection. The protective relays at the interconnection customer's facility will need to be set to detect any fault in the zone of protection and shall isolate the interconnection customer's generator from PacifiCorp's system with no delay. Since the protective relays cannot be set to detect 100 percent of the faults without detecting and operating for faults outside the zone of protection, the interconnection customer's generator will be disconnected for fault conditions that normally would not require isolation of the generator. With the use of a pilot relaying system or direct transfer trip, the number of these unnecessary operations can be greatly reduced.

PacifiCorp may sometimes require installation of a distribution line protective relay at the interconnection customer's sub-site. This is commonly the case whenever three-terminal permissive overreach transfer trip (POTT) schemes are employed to protect the line. Because this line relay participates in a scheme to protect the PacifiCorp distribution system, PacifiCorp must ensure the maintenance, testing, and reliability of this particular type of relay.

The PacifiCorp required relays must be located so that a fault on any phase of the PacifiCorp line shall be detected. If transfer trip protection is required by PacifiCorp, the interconnection customer shall provide at its expense a voice-grade communications circuit. This circuit may be a communication line from the telephone company or a dedicated cable. The line must have high-voltage protection equipment on the entrance cable so that the transfer trip equipment will operate properly during fault conditions. (For a detailed description of protection requirements of the transfer trip equipment, refer to Appendix B.)

The PacifiCorp distribution network system is designed for high reliability by having multiple sources and paths to supply customers. Due to these multiple sources and paths, more complex protection schemes are required to properly detect and isolate faults. The addition of any new generation facility to the PacifiCorp system must not degrade the existing protection and control schemes or cause existing PacifiCorp customers to suffer lower levels of safety and/or reliability.

5.6 Generator Protection and Control

Single phase generators must be connected in multiple units so that an equal amount of generation capacity is applied to each phase of a three-phase circuit.

All synchronous, induction, and single-phase generators shall comply with the latest ANSI Standards (C50.10 and C50.13), dealing with waveform and telephone interference.

Synchronous generators of any size require: a) synchronizing relays (device no. 25) to supervise generator breaker closing, and b) reclose blocking at the PacifiCorp side of the line to which the generator is connected (applies to substation breaker/recloser and line reclosers). If coordinated protection is desired by the interconnection customer, policy device numbers for commonly used protective elements can be found in Table 3. Coordinated protection will minimize the number of times the generator is forced offline without a dedicated feed.

The generator protection should appropriately protect the generation entinty's facility and trip in a reasonable time for any faults in said facility.

5.7 Dedicated Transformer

The dedicated transformer steps up the generator voltage to the interconnection level and isolates the interconnection customer from other customers.

The importance of a dedicated transformer with a delta on the PacifiCorp side and a wye-ground on the generator entity side (delta/wye-gnd) is that the delta isolates the two systems from a ground fault caused by the other system. This connection does not provide a source of zero sequence current to impact the PacifiCorp distribution system's ground relay coordination. The delta winding will also reduce the PacifiCorp system harmonics entering the generation facility, hence it reduces the potential damage to both parties.

A high-side fault-interrupting device, such as a breaker or recloser, is required for transformer protection. It is also required that the device be gang-operated so as to avoid the possibility of ferroresonance or loss of phase condition.

Lightning arrestors, if the interconnection customer chooses to install them, must be installed between the transformer and the fault-interrupting devices and shall be encompassed by the generator's relay protection zone.

5.8 Manual Disconnect Switch

A manual disconnect switch is required for a generation facility. For connections to the PacifiCorp distribution system, a tap-line switch may also be required if, in PacifiCorp's judgment, sufficient tap-line exposure exists to warrant it. Refer to Appendix K for more details on tap-line switches. The installation of line selector switches may impact the protection requirements for the interconnection, specifically the need for direct transfer trip.

A PacifiCorp-operated disconnect device must be provided as a means of electrically isolating the PacifiCorp system from the generator. This device shall be used to establish visually open working clearance for maintenance and repair work in accordance with PacifiCorp safety rules and practices. A disconnect device must be located at the point of interconnection with PacifiCorp for interconnections 2.4 kV and above. The disconnect should be a gang-operated, three-pole lockable switch. PacifiCorp shall own, operate, and maintain all disconnect switches for generation interconnection facilities. The disconnect switch shall be specified by the appropriate PacifiCorp engineers working on the interconnection project and shall come from PacifiCorp stock and be installed on PacifiCorp-owned facilities. PacifiCorp will notify the interconnection customer in advance of the operation of the disconnect switch and follow all work practices associated with this procedure. In the event of an emergency or an unanticipated urgent incident, it will be assumed that notification of the developer for operation of the disconnect switch cannot be assured. Any deviation from this policy shall be signed off by a Vice-President of Engineering at PacifiCorp along with corporate legal counsel and shall be included in the interconnection agreement between PacifiCorp and the interconnection customer with an explanation of why this policy was not followed for the specific project.

For cases in which the state or federal regulatory policy conflicts with PacifiCorp's policy, the state and/or federal regulatory policy shall prevail.

The developer may at its option install a second disconnect switch on its property to operate as its sees fit. PacifiCorp asks that the developer notify PacifiCorp dispatch center before operation of the disconnect switch.

If another disconnect switch is to be located on the developer's site, it must be furnished, installed, owned, and maintained by the interconnection customer. Only devices specifically approved by PacifiCorp may be used. PacifiCorp personnel shall inspect and approve the installation before parallel operation is permitted. If the disconnect device is in the interconnection customer's substation, it should be located on the substation dead-end structure and must have a PacifiCorp-approved operating platform.

The disconnect device must not be used to make or break parallels between the PacifiCorp system and the generator(s). The device enclosure and operating handle (when present) shall be kept locked at all times with PacifiCorp padlocks.

The disconnect device shall be physically located for ease of access and visibility to PacifiCorp personnel. When installed on the interconnection customer's side of the interconnection, the device shall normally be installed close to (i.e., within one foot of) the metering. The PacifiCorp-operated disconnect shall be identified with a PacifiCorp-designated switch number plate.

Metering is normally on the high side of the interconnection customer's dedicated transformers. Between the metering units and the circuit breaker, a second disconnect device is required; it shall not have a PacifiCorp lock and may be operated by the interconnection customer.

5.8.1 Specifications

1. Disconnect switches must be rated for the voltage and current requirements of the specific installation.
2. Disconnect switches must be gang-operated.
3. Disconnect switches must be weatherproof or designed to withstand exposure to weather.
4. Disconnect switches must be lockable in both the open/closed positions with a standard PacifiCorp lock if the switch is located at a PacifiCorp facility.

5.8.2 High-Voltage Disconnects

The interconnection customer shall submit a proposed switch specification to PacifiCorp for approval prior to ordering and installing.

5.9 Discontinuation of Operation

Producers must discontinue parallel operation when requested by PacifiCorp for the following reasons:

1. To facilitate maintenance, test, or repair PacifiCorp facilities. PacifiCorp will coordinate this with each producer.
2. During system emergencies.
3. When a generator is interfering with other PacifiCorp customers or producers on the system.
4. When an inspection of a generator reveals either conditions hazardous to the PacifiCorp system or personnel or a lack of scheduled maintenance or maintenance records for equipment necessary to protect PacifiCorp's system.

5.10 Fault-Interrupting Devices

The fault-interrupting device selected by the interconnection customer must be reviewed and approved by PacifiCorp for each particular application.

There are two basic types of fault-interrupting devices:
- Circuit Breakers
- Reclosers

The type of fault-interrupting device required for a generation facility must be determined based on the size and type of generation, the available fault duty, the local circuit configuration, and the existing PacifiCorp protection equipment.

5.10.1 Circuit Breakers

Three-phase circuit breakers at the point of interconnection automatically separate the generation facility from the PacifiCorp system upon detection of a circuit fault. Additional breakers and protective relays may be installed in the generation facility for ease in operating and protecting the facility. The interconnection breakers must have sufficient capacity to interrupt maximum available fault current at its location and shall be equipped with accessories to:

1. Trip the breaker with an external trip signal supplied through a battery (shunt trip).
2. Telemeter the breaker status when it is required.
3. Lockout if operated by protective relays required for interconnection.

Generally, a three-phase circuit breaker is the required fault-interruption device at the point of interconnection, due to its simultaneous three-phase operation and ability to coordinate with PacifiCorp line-side devices

5.10.2 Reclosers

Reclosers are a single- or three-phase protective device used on distribution circuits.

An automatic circuit recloser is designed to: 1) sense overcurrents, 2) time and interrupt the overcurrent according to a preset characteristic, and 3) reclose to test and possibly reenergize the line after a specified time interval. A recloser should operate several times (usually three or four) before isolating the source of overcurrent from the rest of the system. Since most distribution overcurrents are caused by temporary faults such as tree limb contact in a wind storm, a high probability exists that a recloser can restore service without an outage to customers.

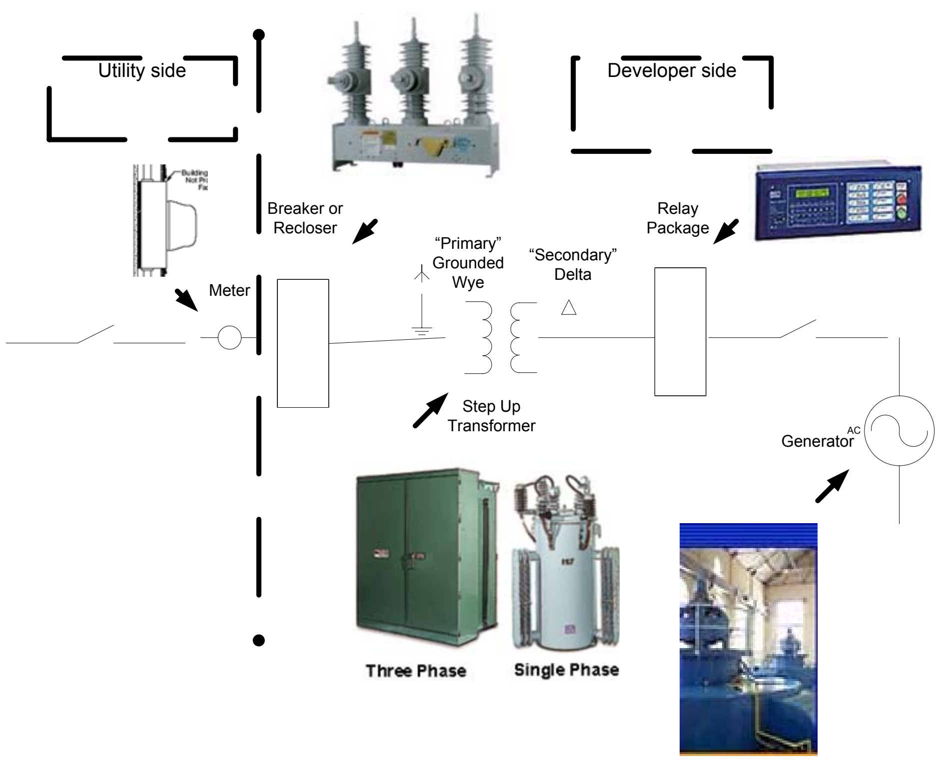
When generation is introduced into circuits that have reclosers, the following alterations may be necessary to the existing units:

1. Change the control to one that is capable of handling generation.
2. Add PTs and CTs to install a hot-line block feature.
3. Change the entire installation if both the control and recloser are too antiquated to accommodate generation. This will be determined by the Local Area Engineer.
4. The unit and control may need to be moved to a different location to better protect the circuit because of the change the added generator introduces to the circuit.

Please refer to the applicable interconnection study results for project-specific details.

For generation projects 250 kW or greater in size, PacifiCorp will require the installation of a breaker or recloser near the point of interconnection (see Figure 2).

Figure 2–Interconnection Equipment Placement and Ownership on Distribution Voltages



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Policy

5.11 Synchronous Generators

The generating unit must meet all applicable American National Standard Institute (ANSI) and Institute of Electrical and Electronic Engineers (IEEE) policies. The prime mover and the generator shall also be able to operate within the full range of voltage and frequency excursions that may exist on the PacifiCorp system without damage to the equipment. The generating unit must be able to operate through the specified frequency ranges for the time durations listed in Table 6, to enhance system stability during a system disturbance.

5.11.1 Synchronizing Relays

Synchronous generators and other generators with stand alone capability must use one of the following methods to synchronize with the PacifiCorp system:

1. Automatic Synchronization with Automatic Synchronizing (Device 25)

   The automatic synchronizing relay must have a slip frequency-matching window of 0.1 Hz or less, a voltage-matching window of ± 10 percent or less, a phase angle-acceptance window of ± 10 degrees or less, and breaker-closure time compensation.

   The automatic synchronizing relay sends a close signal to the breaker after the above conditions are met.

2. Automatic Synchronization with Automatic Synchronizer (Device 15/25)

   The automatic synchronizing relay must have a slip frequency-matching window of 0.1 Hz or less, a voltage-matching window of ± 10 percent or less, a phase angle-acceptance window of ± 10 degrees or less, and breaker-closure time compensation. For an automatic synchronizer which does not have breaker-closure time compensation, a tighter frequency window (± 5 degrees) with a one-second time acceptance window shall be used to achieve synchronization within ± 10 degrees phase angle.

   In addition to the above characteristics, this automatic synchronizer has the ability to adjust generator voltage and frequency automatically to match system voltage and frequency.

3. Manual Synchronization with Synchroscope and Synch Check (Device 25) Relay Supervision

   The synch check relay must have a voltage-matching window of ± 10 percent or less and a phase angle-acceptance window of ± 10 degrees or less.

   Generators with greater than 1,000 kW aggregate nameplate rating must have automatic synchronizing relay or automatic synchronizer.

5.11.2 Frequency/Speed Control

Unless otherwise specified by PacifiCorp, a governor shall be required on the prime mover to enhance system stability. Governor characteristics shall be set to provide a five percent droop characteristic (a 0.15 Hz change in the generator speed shall cause a five percent change in the generator load). Governors on the prime mover must be operated unrestrained to help regulate PacifiCorp's system frequency.

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5.11.3 Excitation System Requirements

An excitation system is required to regulate generator output voltage.

Static systems shall have a minimum ceiling voltage of 150 percent of rated full load field voltage with 70 percent of generator terminal voltage and a maximum response time of two cycles (0.033 seconds).

Rotating systems shall have an ANSI voltage response ratio of 2.0 or faster.

Excitation systems shall respond to system disturbances equally in both the buck and boost directions.

Under certain conditions, PacifiCorp may grant an exemption for generation facilities which have excitation systems not meeting these requirements. Requests for exemption should be sent to PacifiCorp's Distribution Account Manager.

5.11.4 Voltage Regulator Bank

The regulator bank must be able to maintain the generator voltage under steady state conditions without hunting and within ± 0.5 percent of any voltage level between 95 percent and 105 percent of the rated generator. The point of voltage sensing should be at the same point as the PacifiCorp revenue metering. As determined by the PacifiCorp Control Center, the generator shall be operated at either a voltage or a power factor schedule.

Depending on interconnection study results, the generating facility may also be requested by the PacifiCorp Control Center to produce more or less reactive power from that indicated on the regular schedule in order to meet the system needs.

Existing regulator banks on the distribution feeder may need to have their existing controls altered or replaced to accommodate bi-directional power flow. This will be outlined in the interconnection study report.

5.11.5 Power Factor Controller

The controller must be able to maintain a power factor setting within ± 1 percent of the setting at full load at any set point between 95 percent lagging and 95 percent leading. In addition, all power factor controllers for synchronous generators greater than 1 MW must have programmable capability to vary hourly settings.

5.11.6 Data Gathering/Event Recorder

Generation facilities with capacity greater than 250 kW and with automatic- or remotely-initiated paralleling capability may, at PacifiCorp's discretion, have an event recorder utilized by a power quality consulting firm or by PacifiCorp's Engineering Department to investigate operational difficulties encountered with the generator. The event recorder shall provide PacifiCorp with sufficient information to determine the status of the generation facility during system disturbances. The event recorder must provide remote access from PacifiCorp's Control Center or engineering offices. The cost of this recorder and its utilization and operation will be borne entirely by the interconnection customer/owner. It will be assumed that data-gathering and event-recording devices are only installed to resolve specific incidents that arise relating to the generation facility, they are not intended to be installed on a permanent basis.

PacifiCorp Field Engineers may request 15-minute data for any generation facility tied to PacifiCorp circuits. This can be done by either calling or e-mailing the Rocky Mountain Power Commercial and Trading Dept. Manager at (801)220-2542. Please list the type and dates of the data needed and an electronic file will be created and sent via e-mail. If it is found that existing data is not available from the meter, it is possible that the meter can be reprogrammed to access this data. This request can be submitted by contacting Rocky Mountain Power's Metering Dept. at (801)220-2424 or Pacific Power's Metering Dept. at (503)813-5249.

5.11.7 Generator Testing

Testing of the generator and excitation system must be performed to verify proper parameters of the generator and exciter. Testing shall meet the requirements of the WECC Generator Testing Program. Copies of the test reports with appropriate power flow and stability data parameters identified shall be provided to the PacifiCorp Distribution Account Manager. If a stability model is not available, the interconnection entity will be responsible for developing a suitable model for use in PacifiCorp's transient stability program.

5.11.8 Induction Generators

Induction generators and other generators with no inherent var (reactive power) control capability shall be required to provide power to the unity point of interconnection within the range of ± 95 percent power factor as is technically feasible without risk of self-excitation. The induction generator will provide an amount of reactive power equivalent to that required for a synchronous generator and shall be controllable by voltage. Induction generators may also be required to follow a PacifiCorp-specified voltage or var schedule on an hourly, daily, or seasonal basis, depending on the location of the installation. Specific requirement instructions shall be evaluated on a case-by-case basis and shall be provided by the PacifiCorp Control Center

5.12 DC Generators

5.12.1 Inverters Capable of Stand-Alone Operation

Inverters capable of stand-alone operation are capable of islanding, operation, and shall have similar functional requirements as synchronous generators. For units less than 100 kW, it is usually acceptable to have the frequency and voltage functions built into the electronics of the inverter if the set points of these built-in protective functions are tamperproof and can be easily and reliably tested. The total harmonic distortion in the output current of the inverters must meet ANSI and IEEE Standard 519 requirements.

Inverter type generators connected to the PacifiCorp system must be pre-approved by PacifiCorp. For units over 10 kW, a dedicated transformer will be required to minimize the harmonics entering into the PacifiCorp system.

5.12.2 Inverters Incapable of Stand-Alone Operation

Inverters, rated 10 kW or less, that have been tested and certified by Underwriter Laboratories (UL-1741) to be non-islanding, and which meet IEEE Standard 519 harmonic requirements, may be interconnected to the PacifiCorp system as is. Certified non islanding inverters over 10 kW will require a dedicated transformer and may have other requirements depending on the installation location and local generation penetration.

5.13 Emergency Generator Requirement

There are two major methods of transferring electric power supply between the PacifiCorp source and the emergency generator system: open transition (break-before-make) and closed transition (make-before-break). The open transition method can be accomplished via a double-throw transfer switch or an interlock scheme which prevents the two systems from operating in parallel. The interconnection customer's main breaker shall not be allowed to close until the generator breaker opens. This open transition method does not require any additional protection equipment, however it does cause the interconnection customer's load to experience an outage while transferring back to PacifiCorp. The length of this transfer outage depends on the transfer equipment involved.

Emergency systems are routinely tested by the interconnection customer under load, usually once a month. With a break-before-make system, the interconnection customer's load, or most often a portion of it, is removed from the PacifiCorp system and the emergency generator is tested under load conditions. After successful completion of the test, the generator is taken offline and the interconnection customer is transferred back to PacifiCorp. This testing procedure results in the test load experiencing two outages (when bringing the emergency generator online and when taking it offline) whenever the system is tested.

For generation facilities that cannot tolerate this momentary loss of power, the closed transition (make-before-break) method is intended to provide transfer without interruption. For the closed-transition method, the maximum parallel time with the PacifiCorp system shall be less than 0.5 seconds, both to and from the emergency generator source. The protection requirements for synchronous generators will also apply to emergency generators any time a parallel is to be made with the PacifiCorp system. These would include, but are not limited to, a dedicated transformer and automatic synchronizing.

PacifiCorp may, at its discretion, allow installation of three very sensitive, single-phase, reverse-power relays (such as the Basler BE1-32R) for emergency generator installations, as an alternative to the normally required voltage, frequency, and ground relays. The reverse power relays shall be set to pick up on transformer magnetizing current with a time delay not to exceed 0.5 second. The reverse power relay, in this case, will protect PacifiCorp personnel and the general public by preventing the generator from keeping the PacifiCorp system energized in the event the PacifiCorp source substation(s) have tripped for a fault while the generator is paralleled. The relay output shall trip the circuit breaker on the PacifiCorp side of the transfer switch. This application can be used when the interconnection customer's emergency generator output is expected to be less than the entity's load.

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5.14 Notification/Documentation

The interconnection customer must notify its local PacifiCorp representative in writing of all new proposed emergency generator installations, or proposed changes to the existing schemes, regardless of method of interconnection or transfer.

Required documentation includes a description of generation and control system operation, one-line diagrams, identification of all interlocks, sequence of events description for transfer operation, and specifications for any PacifiCorp-required protective devices. PacifiCorp may request additional documentation should it deem it necessary. Depending on the complexity of the installation, PacifiCorp may require a professional engineering review by an electrical engineer from the state in which the generator is to reside. Please consult with the Distribution Account Manager with any questions.

All documentation must be approved by PacifiCorp Engineering prior to installation.

5.15 Operation/Clearances

For the safety of PacifiCorp personnel and to ensure the proper operation of the PacifiCorp system, it is essential that the interconnection customer notify the PacifiCorp Control Center of all emergency generator installations prior to paralleling. For operation and clearance purposes, emergency generator installations should be treated the same as any independent generation facility interconnected to the PacifiCorp system. A satisfactory visible open point shall be approved by PacifiCorp.

For all line work and clearances, the emergency generator shall be treated as a power source.

Interconnection customers using make-before-break transfer schemes are required to notify the PacifiCorp Control Center of their intent to transfer to their emergency generator and then back to the PacifiCorp source before any transfers are attempted. The notification of the make-before-break transfer scheme is necessary because such actions put another generation source in parallel with the PacifiCorp system. This notification is not essential on break-before-make schemes, but may be desirable in some instances.

5.16 Parallel-Only (No-Sale) Generator Policy

Parallel-only generators shall have similar requirements as that of any other standard synchronous generator interconnection except that PacifiCorp may at its discretion allow the installation of three very sensitive, single-phase, reverse-power relays (such as the Basler BE 1 32R) along with the dedicated transformer as an alternative to the normally required interconnection protection relays. The reverse power relays shall be set to pick up on transformer magnetizing current with a time delay not to exceed 0.5 second. This option may not be feasible on generating systems with a slow load-rejection response since they may be tripped offline frequently for in-plant disturbances.

Owners of parallel-only generators must execute a parallel-only (no-sale) operating agreement with PacifiCorp prior to operation by the generation owner/developer.

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5.17 Interconnection Customer-Owned Primary or Distribution Voltage Tap Lines (2.4 kV and Above)

If the interconnection customer constructs, owns, and maintains a primary level or distribution-level voltage tap-line extension, the entity shall also install, own, and maintain the following equipment at the point of interconnection with PacifiCorp:

- Fault-interrupting protection device (i.e., breaker or recloser, as specified by PacifiCorp).
- Manual isolating disconnects (gang-operated).
- High-side metering installation as outlined in Section 4.

5.18 PacifiCorp Protection and Control System Changes

At the interconnection customer's expense, PacifiCorp will perform a detailed interconnection study to identify the cost of any required modifications to PacifiCorp's protection and control systems to interconnect a new generation source. A Generation Special Facilities Agreement shall be executed to recover the costs to PacifiCorp associated with any protection and control system modifications which are directly assigned to the interconnection customer. These protection and control system modifications are in addition to any distribution system upgrades identified in the system impact or facilities studies for interconnection of the new generation facility.

Following is a partial list of protection system modifications which may be required:

- PacifiCorp's automatic restoration equipment shall be prevented from operating until the generator is below 25 percent of nominal voltage as measured at the restoration equipment. Generator damage and system disturbances may result from the restoration of power by automatically re-energizing PacifiCorp's facilities. This modification shall be required when the generator has the capability of energizing a line while the PacifiCorp system is disconnected. PacifiCorp will not allow the interconnection customer's generator to automatically re-energize PacifiCorp facilities.
- For generation facilities greater than 1,000 kW aggregate nameplate rating, all existing single-phase fault-interrupting devices (fuses) located in series between the generator and PacifiCorp's substation shall be replaced with three-phase interrupting devices to prevent possible single-phasing of other customers.
- PacifiCorp substation transformer high-side fuses must be replaced with a three-phase interrupting device when the generator is on a distribution circuit fed from a fused PacifiCorp substation transformer bank, and the bank's minimum load is equal to or less than 200 percent of the generator's nameplate rating.
- Installation of transfer trip from the high-side circuit breaker/circuit switcher, as well as the distribution breaker and any line reclosers, to the generator may be required if deemed necessary by circuit conditions. An associated alarm circuit is required between the interconnection customer's site and the PacifiCorp Control Center.

These ride through and trip settings are required for the protection of PacifiCorp's system. The required devices and settings will be installed at the Point of Interconnection (POI). The protection devices at the POI will send trip signals to the generator breakers (or to the wind turbine feeder breakers if a wind plant). The interconnection customer may also have frequency and voltage protection at its generating facility. The interconnection customer's local protection settings must be compatible with the voltage and frequency ride-through requirements in Table 2

Table 2–Ride-Through and Trip Voltage/Frequency Relay Settings

Frequency Ride-Through Required (see Note 1)	**Trip Required**	**Voltage Ride-Through Required (see Note 1)**	**Trip Required**
(Hz, delay(sec))	(Hz, delay(sec))	(pu, delay(sec))	(pu, delay(sec))
	> 61.6, 0.0		> 1.500, 0.1
	> 60.5-61.6, 0.5		1.10-1.49, 2.0
60.5-59.5, infinite	< 59.5-58.4, 0.5	.950-1.05, infinite	1.099-1.051, 120.0
	< 58.4, 0.0		0.949-0.901, 120.0
			0.900-0.671, 2.0
			< 0.671, 0.1

Notes:

1. Outside of range/time delay, trip permitted but not required

Table 3–WECC Disturbance-Performance Table of Allowable Effects on Other Systems

NERC and WECC Categories	Outage Frequency Associated with Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (see Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed 25% at load buses or 30% at non-load buses Not to exceed 20% for more than 20 cycles at load buses	Not below 59.6 Hz for 6 cycles or more at a load bus	Not to exceed 5% at any bus
C	0.033 - 0.33	Not to exceed 30% at any bus Not to exceed 20% for more than 40 cycles at load buses	Not below 59.0 Hz for 6 cycles or more at a load bus	Not to exceed 10% at any bus
D	< 0.033	Nothing in addition to NERC		

Notes:

1. The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.

2. As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

3. Additional voltage requirements associated with voltage stability are specified in WECC Standard I-D. If it can be demonstrated that post-transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.

5.19 Telemetry and SCADA Requirements

In order to fully comply with NERC Reliability Standards TOP-005-1, *Operational Reliability Information* and FAC-001-0, *Facility Connection Requirements*, Grid Ops will need the following SCADA and tone-telemetered generator data for 3 MW and higher plants connected to PacifiCorp system:

1. Status (of breakers).
2. MW and MVAR capability.

3. MW and MVAR net output.
4. Status of automatic voltage control facilities (i.e., capacitors, reactors, dynamic VAR devices).

   The same standard requires that key voltages be metered (and that PacifiCorp's voltage requirements adequately address this need).
5. Tone telemetry.

5.20 Digital Control (DDC)

Dispatchable generators larger than 3,000 kW are required to have real-time direct digital control of unit output from PacifiCorp's Control Center. This allows generation units to respond to power system load/frequency changes.

5.21 Warning Label for Protective Relays

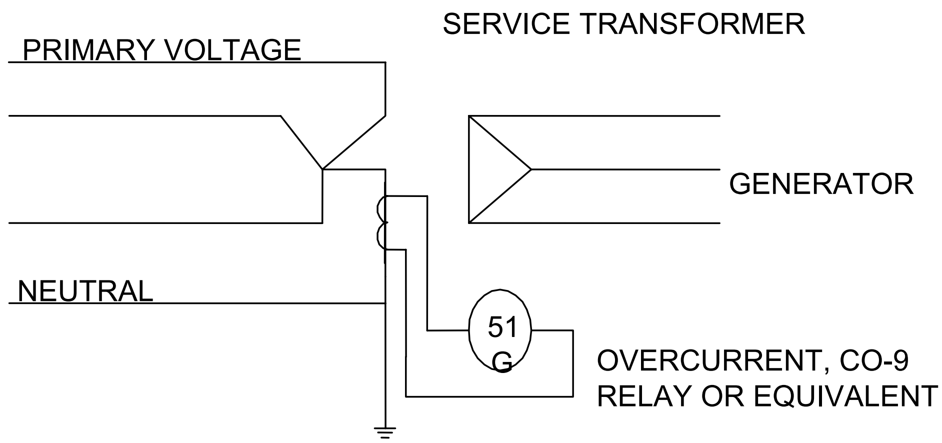
A warning label shall be affixed within 6 inches of any relay in the interconnection customer's control house (or similiar enclosure containing protective relays) **which affects the operation of PacifiCorp's electrical circuits**. The warning label shall state the following:

> ***Warning !!!*** *Do not alter or change any settings on this relay without first receiving approval from PacifiCorp's Protection and Control Engineering Dept. in Portland, Oregon. Failure to give notification to PacifiCorp of this action may result in damaged or destroyed electrical equipment, possible physical injury or fatality, facility disconnection, and/or legal action.*

A stock item number is available from Pacificorp to acquire this item. Please contact PacifiCorp's Local Area Engineer and/or a Distribution Account Manager to acquire this label.

Figure 3–Recommended Ground Detection Schemes on Primary Voltage Circuits

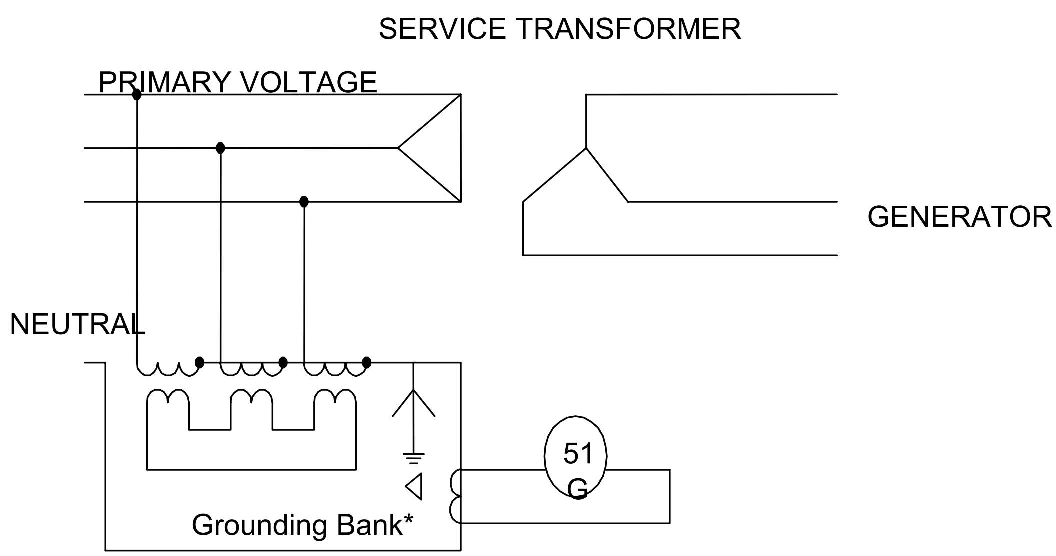
Wire System, Service Transformer Connected Ground Wye on Primary Voltage Side



Notes:

1. CT ratio to be selected according to ground fault currents for the location.

Wire System, Service Transformer Connected Delta on Primary Voltage Side



Notes:

1. Grounding Bank to be sized to limit overvoltages to 1.15 times normal voltage.

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6 GENERATOR REACTIVE AND VOLTAGE POLICY

The purpose of this section is to help all generation facilities satisfy applicable PacifiCorp policies and procedures.

The policies and procedures of this section apply to all generators interconnecting with the PacifiCorp power system. All generators must meet applicable WECC (Western Electricity Coordinating Council) policies.

Generation facilities are required to schedule energy or ancillary services through a designated scheduling coordinator unless other arrangements have been made with PacifiCorp.

6.1 Reactive and Voltage Control Policy for Generators

Reactive power (var) and voltage control are vital components of desired PacifiCorp system operation. It is essential that PacifiCorp receive both real and reactive power from interconnected generators. Where a generator is unable to furnish reactive power support due to interconnection limitations, type of generator, generator loading, or other reasons, the interconnection customer shall install equivalent reactive support at the customer's expense or make other arrangements with PacifiCorp.

How a generator meets PacifiCorp's reactive requirements depends on its type and size. Synchronous generators have an inherent reactive flexibility that allows them to operate within a range to either produce or absorb vars. Unless they have installed corrective equipment, induction generators operate at a power factor absorbing vars and require reactive support from the interconnected system.

Interconnection customers must provide reactive supply sufficient to operate at as near unity power factor as can be safely achieved without risk of self excitation. Typically the power factor should range from 97 percent leading power factor (absorbing vars) and 1.0 (unity). PacifiCorp may further require the provision of reactive support equivalent to that provided by operating a synchronous generator anywhere within the range from 95 percent leading power factor (absorbing vars) to 95 percent lagging power factor (producing vars) within an operating range of ± 5 percent of rated generator terminal voltage and full load. This is typical if the induction generators shall be equipped and operated to control voltage. If the facility is not capable of providing positive reactive support (supplying reactive power to the system) immediately following the removal of a fault or other transient low-voltage perturbations, the facility may be required to add dynamic voltage support equipment.

6.1.1 Generator Control

6.1.1.1 Voltage Control

Voltage regulators are required for all generators larger than 100 kW. In some cases, particularly for small units connected to the distribution system, a power factor controller will also be required to provide operational flexibility.

Voltage regulators must be capable of maintaining the interconnection reactive interchange between 0.95 leading/lagging power factor measured at the point of interconnection. For synchronous machines, the regulators and exciters will be required to react during faults (i.e., within cycles). For wind farms that will have induction machines installed, PacifiCorp may accept slower adjustments to voltage regulation on a case-by-case basis.

The generator shall normally be operated with the generator automatic voltage regulator in a constant voltage regulation mode. The voltage regulator shall be adjusted periodically throughout each day to maintain reactive output within a range defined by PacifiCorp and consistent with the reactive requirements for the local transmission system. This may be a voltage that minimizes the reactive interchange between PacifiCorp's system and the generation facility, or, at PacifCorp's discretion, the PacifiCorp dispatcher may ask the plant operator to hold a higher or lower voltage so as to cause the facility to supply or absorb reactive power in support of specific system control objectives. It is the owner's responsibility to insure that the transformer tap position and all other equipment are compatible with this objective.

In the event that the generator by itself is not capable of providing sufficient reactive power at the point of interconnection so as to supply reactive power to the system sufficient to meet the 0.95 leading/lagging power factor requirement, switched shunt capacitors or dynamic var equipment may be required (as determined by the interconnection study). The generating facility's operation shall limit abrupt voltage changes on PacifiCorp's system to ± 3 percent.

Special considerations may require the use of line-drop compensation to partially compensate for reactive losses of the generator step-up transformer and/or other impedances between the generator and the point of interconnection. If required, the control system should allow for up to 50 percent compensation of said losses. The need for line-drop compensation will be at the sole discretion of PacifiCorp

6.1.1.2 Power Factor Control

For units smaller than 100 kW and/or in special cases as mutually agreed, a power factor controller shall be utilized to maintain a constant power factor at the point of interconnection by controlling the voltage regulator or other relevant equipment. The controller must be capable of maintaining a power factor within ± 1 percent at full load at any set point between 95 percent lagging (producing vars) and 95 percent leading (absorbing vars) measured at the point of interconnection. In addition, all power factor controllers for generators larger than 1,000 kW must have programmable capability to vary hourly settings. The PacifiCorp Control Center shall specify required settings for voltage or power factor. Generally, as noted above, a voltage will be specified that minimizes the reactive interchange between PacifiCorp's system and the generating facility.

In the event that the generator by itself is not capable of providing sufficient reactive power at the point of interconnection so as to supply reactive power to the system sufficient to meet the 0.95 leading/lagging power factor requirement, switched shunt compensation or dynamic var equipment may be required

The programmable controller for units larger than 1,000 kW is normally obtained by combining a non-programmable controller and a general-purpose programmable device.

Control over the var production associated with the delivery of power to PacifiCorp falls under the following general classifications, depending upon the contractual arrangements:

6.1.1.2.1 Surplus-Sale Operation

When an interconnection customer dedicates its generator to serving plant needs first, selling only the surplus to PacifiCorp, treatment differs depending on whether excess power is being *sold to* PacifiCorp or supplemental power (no-sale mode) is being *purchased from* PacifiCorp. In a no-sale mode, the interconnection customer has sole control over var production, however the customer shall meet the power factor requirements for its overall facility as described by the applicable tariff(s). When surplus power is being sold, PacifiCorp has operational control of the power factor at which the power is delivered.

6.1.1.2.2 Net-Sale Operation

All electricity produced, excluding station load, is sold to PacifiCorp. PacifiCorp therefore has operational control of var production within the generator operating range.

6.1.1.2.3 No-Sale Operation

When an interconnection customer uses generation exclusively to offset load, the customer has sole control of the generator power factor, however the customer shall meet the power factor requirements for its overall facility as described by the applicable tariff(s).

6.1.1.2.4 Generation Connected to the PacifiCorp Power System (< 1 MW and Total Output Sold to PacifiCorp):

All electricity produced, excluding station load, isvar production within the generator operating range.

6.2 Synchronous Generator Frequency/Speed Control

To enhance system stability, a governor is required on the prime mover, set to provide a 5 percent droop characteristic (a change of 0.15 Hz in the generator speed will cause a 5 percent change in the generator load). Exceptions must be approved by PacifiCorp. Governors shall be operated unrestrained to regulate system frequency.

6.2.1 Non-Synchronous Generator Control (without Var Control)

Induction generators or other generators without var control absorb vars and therefore require reactive power support from PacifiCorp's system. For facilities larger than 40 kW, PacifiCorp will require power factor correction. Power factor correction or capacitors must be installed either by the interconnection customer or as part of the special facilities installed by PacifiCorp at customer expense. Care must be exercised by the interconnection customer in connecting capacitors directly to the generator terminals to avoid self-excitation. Stand-alone switched capacitors supplied by the interconnection customer which are not an integral part of the generator control system shall be switched on and off at the request of PacifiCorp.

When the generator is located at a remote location on an existing distribution line, severe circuit voltage regulation problems may result if all the interconnection customer's capacitors are located at the generator terminals. In such cases, the generator can be operated at a power factor less than unity (absorbing vars) with part of the generator reactive supply furnished from capacitors located elsewhere on the PacifiCorp system. If this solution is adopted, the interconnection customer will bear the cost of the capacitor installation(s) as well as the maintenance of these units. The maintanence charges will be included in the interconnection agreement for the interconnection customer.

6.2.2 Induction Generators

Switched capacitors may be required by PacifiCorp in areas where severe reactive limitations exist. The need for the capacitors as well as the specifics of their size, location, and operational limitations will be outlined in the interconnection study report results. The interconnection customer must provide reactive supply sufficient to operate at as near unity power factor as can be safely achieved without risk of self-excitation. Typically the power factor should range from 97 percent leading power factor (absorbing vars) and 1.0 (unity). PacifiCorp may further require the provision of reactive support equivalent to that provided by operating a synchronous generator anywhere within the range from 95 percent leading power factor (absorbing vars) to 95 percent lagging power factor (producing vars) within an operating range of ± 5 percent of rated generator terminal voltage and full load. (This is typical if the induction project is greater than 1,000 kW.)

6.2.3 Generator Step-Up Transformer

The available voltage taps of an interconnection customer's step-up transformer must be reviewed by PacifiCorp for their suitability with PacifiCorp's system. The Interconnection customer is expected to request this review before acquiring the transformer.

PacifiCorp shall determine which voltage taps would be suitable for a step-up transformer for the interconnection customer's proposed project. Suitable taps are required in order to give the transformer the essential capacity for the generator to:

- Deliver maximum reactive power to PacifiCorp's system at the point of interconnection (generator operating at 95 percent lagging power factor) and,
- Absorb maximum reactive power from PacifiCorp system (generator operating at 95 percent leading power factor).

The interconnection customer's transformer, with correct voltage taps, helps maintain a specified voltage profile on PacifiCorp's system for varying operating conditions. Actual voltage tap settings can be different for transformers connected at the same voltage level, depending upon their geographic location.

The interconnection customer is responsible for ensuring that the available voltage taps of each interconnection customer's step-up transformer are adequate to best match current distribution system operating voltages provided by PacifiCorp. In addition, suitable taps are required to support a 95 percent power factor at the point of interconnection by delivering or absorbing reactive power as needed. Before acquiring the transformer, the interconnection customer should consult PacifiCorp for assistance in this matter.

6.2.4 Grid Operations

All generation interconnections on distribution level voltages will require as policy a standard breaker-status indication for PacifiCorp's grid operations utilization for day-to-day power system activities. The standard PacifiCorp scheme for reading breaker status of small generating facilities on distribution systems less than 3 MW as of this date is the "ibox." PacifiCorp reserves the right to alter this scheme in the future should technological advances in this arena render this method obsolete and/or more costly. Check with the Distribution Account Manager to see the present system in use for this activity. If this alteration should occur, the ibox method will be grandfathered for each facility where it is utilized by the account manager through amendments to existing agreements/contracts. The "ibox" system will be used with the following communications methods:

1. MAS radio (if a master site is available).
2. Leased telephone line.
3. Other radio systems or set of radios used to bring the SCADA info back to the collection location station.

The following data will be gathered by PacifiCorp in order to fully comply with NERC Reliability Standard TOP-005-1, *Operational Reliability Information* and FAC-001-0, *Facility Connection Requirements*. Grid Ops will need the following SCADA and tone-telemetered generator data for 3 MW and higher plants connected to the PacifiCorp system:

1. Status (of breakers).
2. MW and Mvar capability.
3. MW and Mvar net output.
4. Status of automatic voltage control facilities (capacitors, reactors, dynamic VAR devices).

   The same standard requires that key voltages be metered (and that PacifiCorp's voltage requirements adequately address this need).
5. Tone telemetry.

Note that in WECC units, 10 MVA and above should have automatic voltage regulation (AVR) installed on them.

For installations less than 3 MW, it shall be the policy of PacifiCorp to gather data on breaker status, MW, and Mvar values when the cumulative total generation connected to a feeder breaker or transformer exceeds 3 MW. The generation project proposed which by its interconnection and insertion to the circuit exceeds this threshold shall be responsible for installing a system to acquire the aforementioned data points for its project and transmitting them to the regional dispatcher monitoring distribution circuits. If the addition of the proposed project does not exceed the circuit's total connected generation nameplate level above 3 MW, no additional equipment will be required.

7 POWER QUALITY POLICY

7.1 Voltage Fluctuation Limits

The interconnection customer should expect a normal operating voltage range of ± 5 percent from nominal. The owner/developer should contact PacifiCorp to determine the normal operating voltage at their point of interconnection The plant shall be capable of start-up whenever the voltage at the point of interconnection is within this range. If the auxiliary equipment within the generator cannot operate within the above range, the generator will need to provide regulation equipment to limit the station service voltage-level excursions. During system contingency or emergency operation, operating voltages may vary up to ± 10 percent from nominal.

7.1.1 Harmonic Limits

All generators shall comply with the voltage and current harmonic limits specified in IEEE Standard 519 -1992, *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

The harmonic content of the voltage and current waveforms in the PacifiCorp system must be restricted to levels which do not cause interference or equipment operating problems for PacifiCorp or its customers.

Any harmonic problems shall be handled on a case-by-case basis. A generation facility causing harmonic interference is considered by PacifiCorp as a serious interference with service and is subject to disconnection from the PacifiCorp system until the condition has been corrected. If the cause of the problem is traceable to the interconnection customer's facilities, all costs associated with determining and correcting problems shall be at the customer's expense.

Many methods may be used to restrict harmonics. The preferred method is to install a transformer with at least one delta connection between the generator and the PacifiCorp system. This method significantly limits the amount of voltage and current harmonics entering the PacifiCorp system. Generation system configuration with a star-grounded generator and a two-winding (both star-grounded) transformer shall not be allowed.

7.1.2 Voltage Flicker Limits

All generating units shall adhere to PacifiCorp's policy on voltage fluctuation and light flicker at the PCC with PacifiCorp. This issue primarily focuses on wind turbine based generation but may be applicable to other forms of generation. Voltage fluctuation is more pronounced with one or two wind turbines installed on distribution circuits where the X-to-R ratio of the line is high. PacifiCorp's policy is available in the Engineering Handbook, Section 1C.5.1 which can be found on the PacifiCorp website. This policy is based on IEEE Standard 1453 - 2004. It is the generator owner/developer's responsibility to determine the expected Pst flicker values caused by the addition of their generator. It will also be the owner/developer's responsibility to bring the Pst flicker level into compliance with PacifiCorp's policy at the developer's cost should the values exceed PacifiCorp's policy limits at any time during the life of operation of the facility on PacifiCorp's electrical system. This could occur at the time of installation or at a later date.

The developer must allow for reasonable corrective contingencies if system operations or circuit modifications alter the circuit's electrical characteristics.

8 COMMISSIONING POLICY AND INSPECTION PROCEDURE FOR INTERCONNECTION CUSTOMERS

A PacifiCorp meter/relay technician will be the only person allowed to test the meter installed for the generation facility since this equipment is owned by PacifiCorp. Coordination between the developer and PacifiCorp's project manager is recommended to take place at least two months before the start-up date.

PacifiCorp will either utilize its own qualified employees or a contractor from its approved contractor list. Commissioning of any relays which tie with the PacifiCorp system and affect PacifiCorp's customer must be certified by a Professional Engineer licensed in the state in which the interconnection project is located.

It will be the developer/owner's responsibility to provide adequate time for commissioning activities. The developer/owner will provide unrestricted access for PacifiCorp's employees or vendor employees (whichever are utilized) to the equipment to be commissioned. It shall be the developer/owner's responsibility to pay for all commissioning costs

Commissioning testing, where required on either PacifiCorp-owned equipment or equipment that affects the operational integrity of the electrical circuit, will be performed on site to verify protective settings and functionality. Upon initial parallel operation of a generating facility, or any time interface hardware or software is changed that may affect the functions listed below, a commissioning test must be performed. An individual qualified in testing protective equipment (a Professional Engineer, factory-certified technician, or licensed electrician with verifiable experience in testing protective equipment) must perform commissioning testing in accordance with the manufacturer's recommended test procedure to prove that the settings and requirements of PacifiCorp's interconnection study report are met. PacifiCorp reserves the right to witness commissioning tests listed below and requires written certification stamped by a Professional Engineer from the state the in which project resides describing which tests were performed and their accompanying results.

It is preferred but not required for PacifiCorp to perform the commissioning on the customer-owned relay on distribution generators that affects PacifiCorp's customers. This preference is to provide PacifiCorp with greater assurance that the relay was set properly and functions as intended to protect PacifiCorp's customers on the electrical circuit.

Functions to be tested during commissioning will consist of the following:

- Over and undervoltage
- Over and underfrequency
- Anti-islanding function (if applicable)
- Non-export function (if applicable)
- Inability to energize dead line (dead line check)
- Time delay on restart after a utility source is stable
- Utility system fault detection (if used)
- Synchronizing controls (if applicable)
- Other interconnection protective functions that may be required as part of the interconnection agreement.
- Verify final protective relay settings
- Trip test
- In-service test

8.1 Certified Equipment

Generating facilities qualifying for simplified interconnection incorporate certified equipment that have, at a minimum, passed the type test and production tests described in this document and are judged to have little or no potential impact on PacifiCorp's distribution system. For such generating facilities, it is necessary to perform only the following tests:

- Over and undervoltage
- Over and underfrequency
- Anti-islanding function (if applicable)

Protection settings that have been changed after factory testing will require field verification. Tests will be performed using injected secondary quantities, applied waveforms. A test connection using a generator to simulate abnormal utility voltage or frequency, or by varying the set points to show that the device trips at the measured (actual) utility voltage or frequency, will be conducted.

The non-islanding function will be checked by operating a load break disconnect switch to verify that the interconnection equipment ceases to energize the line and does not re-energize for the required time delay after the switch is closed.

The non-export function will be checked using secondary injection techniques. This function may also be tested by adjusting the generating facility output and local loads to verify that the applicable non-export criteria (i.e., reverse power or under power) are met. The supplemental review or interconnection study may impose additional components or additional testing.

8.2 Non-Certified Equipment

Non-certified equipment shall be subjected to the appropriate tests described in Sections 8.1 and 8.9. With PacifiCorp's approval, these tests may be performed in the factory, in the field as part of commissioning, or a combination of both. PacifiCorp, at its discretion, may also approve a reduced set of tests for a particular application or, for example, if it determines it has sufficient experience with the equipment.

8.3 Verification of Settings

If the testing is part of the commissioning process, then, at the completion of such testing, the producer's third-party Professional Engineer shall confirm that all devices are set to PacifiCorp-approved settings. This step shall be documented in the commissioning test certification.

8.4 Trip Tests

Interconnection protective devices (e.g., reverse-power relays) which have not previously been tested as part of the interconnection system with their associated interrupting devices (e.g., contactor or circuit breaker) shall be trip-tested during commissioning. The trip test shall be adequate to prove that the associated interrupting devices open when the protective devices operate. Interlocking circuits between protective devices or between interrupting devices shall be similarly tested unless they are part of a system that has been tested and approved during manufacture.

8.5 In-Service Tests

Interconnection protective devices which have not previously been tested as part of the interconnection system with their associated instrument transformers, or that are wired in the field, shall be given an in-service test during commissioning. This test will verify proper wiring, polarity, CT/PT ratios, and proper operation of the measuring circuits. The in-service test shall be made with the power system energized and carrying a known level of current. A measurement shall be made of the magnitude and phase angle of each AC voltage and current connected to the protective device and the results shall be compared to expected values. For protective devices with built-in metering functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values may be used for in-service testing. Otherwise, portable ammeters, voltmeters, and phase-angle meters shall be used.

8.6 Periodic Testing

Periodic testing of interconnection-related protective functions shall be performed as specified by the manufacturer, or at least every five years. All periodic tests prescribed by the manufacturer shall be performed. The producer shall maintain periodic test reports or a log available for inspection by PacifiCorp. Periodic testing conforming to PacifiCorp test intervals for the particular line section may be specified by PacifiCorp under special circumstances, such as in high fire-hazard areas. A system that depends upon a battery for trip power shall be checked and logged once per month for proper voltage. Once every five years, the battery must be either replaced or a discharge test performed.

8.7 Supplemental Testing Procedures

This section describes the additional type tests necessary to qualify a device as certified for use on PacifiCorp distribution systems. These type tests are not contained in UL 1741, *Standard Inverters, Converters and Controllers for Use in Independent Power Systems*, nor other referenced standards, but are considered necessary for Certification by PacifiCorp.

8.7.1 Non-Exporting Test Procedures

The non-exporting test is intended to verify the operation of relays, controllers, and inverters designed to limit the export of power and certify the equipment as meeting the requirements that power not be exported across the PCC to the PacifiCorp distribution system. Tests are provided for discrete relay packages and for controllers and inverters that include the intended function.

8.7.2 Reverse-Power Relay Test

This version of the non-exporting test procedure is intended for stand-alone reverse power and under-power relay packages provided to block the export of power across the PCC to PacifiCorp's system. It should be understood that in the reverse power application, the relay will provide a trip output with power in the export (toward the PacifiCorp distribution system) direction.

Step 1: Power Flow Test at Minimum, Midpoint, and Maximum Pickup Level Settings

Determine the appropriate secondary pickup current for the desired export power flow of 0.5 secondary watts (the agreed-upon minimum pickup setting, assumes 5 amp and 120V CT/PT secondary). Apply nominal voltage with minimum current setting at zero degrees in the trip direction. Increase the current to pickup level. Observe the relay trip's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within two percent of the expected power. For relays with adjustable settings, repeat this test at the midpoint and maximum settings. Repeat at phase angles of 90, 180, and 270 degrees and verify that the relay does not operate (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Apply rated voltage with a minimum pickup current setting (calculated value for system application) and apply a leading power factor load current in the non-trip direction (current lagging voltage by 135 degrees). Increase the current to relay rated current and verify that the relay does not operate. For relays with adjustable settings, this test should be repeated at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Increase the current level to pickup (about ten times higher than at 0 degrees) and verify that the relay operates. Repeat for phase angles of 90, 180, and 270 degrees and verify that the relay does not operate.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and current at 180 degrees from tripping direction, to simulate normal load conditions (for three-phase relays, use Ia at 180, Ib at 60, and Ic at 300 degrees). Remove phase-one voltage and observe that the relay does not operate. Repeat for phases two and three.

Step 5: Load Current Test

Using the pickup settings determined in Step 1, apply rated voltage and current at 180 degrees from the tripping direction, to simulate normal load conditions (use Ia at 180, Ib at 300, and Ic at 60 degrees). Observe that the relay does not operate.

Step 6: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and two times rated current, to simulate an unbalanced fault in the non-trip direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 180 degrees, Ib at 0 degrees, and Ic at 180 degrees). Observe that the relay, especially single-phase, does not mis-operate.

Step 7: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings.

Step 8: Dielectric Test

Perform the dielectric test described in IEC 414 using 2 kV RMS for one minute.

Step 9: Surge Withstand Test

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in Section 8.9.6 of this policy.

8.7.3 Under-Power Relay Test

In the under-power application, the relay will provide a trip output when import power (toward the producer's generating facility) drops below the specified power level.

For an underpower relay, pickup is defined as the highest power level at which the relay indicates that the power is less than the set setting.

Step 1: Power Flow Test at Minimum, Midpoint, and Maximum Pickup Level Settings

Determine the appropriate secondary pickup current for the desired power flow pickup level of five percent of peak load (the agreed-upon minimum pickup setting). Apply rated voltage and current setting at zero degrees in the direction of normal load current. Decrease the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within two percent of the expected power. For relays with adjustable settings, repeat the test at the midpoint and maximum settings. Repeat at phase angles of 90, 180, and 270 degrees and verify that the relay operates (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Using the pickup current setting determined in Step 1, apply rated voltage and rated leading power factor load current in the normal load direction (current leading voltage by 45 degrees). Decrease the current to 145 percent of the pickup level determined in Step 1 and verify that the relay does not operate. For relays with adjustable settings, repeat the test at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Decrease the current level to pickup (about ten percent of the value at 0 degrees) and verify that the relay operates. Repeat for angles 90, 180, and 270 degrees and verify that the relay operates for any current less than rated current.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and 25 percent of rated current in the normal load direction, to simulate light load conditions. Remove phase-one voltage and observe that the relay does not operate, repeat for phases two and three.

Step 5: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and two times rated current to simulate an unbalanced fault in the normal load direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 0 degrees, Ib at 180 degrees, and Ic at 0 degrees). Observe that the relay, especially single-phase, operates properly.

Step 6: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings.

Step 7: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for one minute.

Step 8: Surge Withstand

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in Section 8.9.6 of this policy.

8.7.4 Functional Tests for Inverters and Controllers

Inverters and controllers designed to provide reverse or under-power functions shall be tested to certify the intended operation of this function. Two methods are provided:

Method 1: If the controller utilizes external current/voltage measurement to determine the reverse or under-power condition, then the controller shall be functionally tested by application of appropriate secondary currents and potentials as described in Section 8.7.2, Reverse Power Relay Test.

Method 2: If external secondary current or potential signals are not used, then unit-specific tests must be conducted to verify that power cannot be exported across the PCC for a period exceeding two seconds. These tests may be factory tests if the measurement and control points are part of a single unit, or may be provided for in the field.

8.8 In-Rush Current Tests

This test will determine the maximum in-rush current drawn by the unit.

8.8.1 Locked-Rotor Method

Use the test procedure defined in NEMA MG-1 (manufacturer's data is acceptable if available).

8.8.2 Start-Up Method

Install and setup the generating facility equipment as specified by the manufacturer. Using a calibrated oscilloscope or data acquisition equipment with appropriate speed and accuracy, measure the current draw at the point of interconnection as the generating facility starts up and parallels with PacifiCorp's distribution system. Startup shall follow the normal, manufacturer-specified procedure. Sufficient time and current resolution and accuracy shall be used to capture the maximum current draw within five percent. In-rush current is defined as the maximum current draw from PacifiCorp during the startup process, using a ten-cycle moving average. During the test, the utility source, real or simulated, must be capable of maintaining voltage within ± 5 percent of rated at the connection to the unit under test. Repeat this test five times. Report the highest ten-cycle current as the in-rush current. A graphical representation of the time-current characteristic along with the certified in-rush current must be included in the test report and made available to PacifiCorp.

8.9 Type Testing

8.9.1 Inverters

Static power inverters shall meet all of the type tests and requirements appropriate for a utility interactive inverter as specified in UL 1741, *Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*. These requirements may be applied to inverters used with electric energy sources other than photovoltaic systems.

A description of key aspects of these procedures is provided in the testing procedures section of this document. Separate test procedures are provided to certify non-islanding functions and non-export functions, to determine the in-rush current tolerance of the distribution system, to subject the device to voltage surge conditions, and to verify the inverter's ability to synchronize with the distribution system.

8.9.2 Synchronous Generators

Until a standardized test procedure written specifically for synchronous generators is identified, PacifiCorp shall determine which of the tests described in this section are appropriate and necessary to certify the performance of the control and protection system functions of the synchronous machine, and how to perform them. The tests listed in Table 4 below and defined in UL 1741 shall be performed as applicable to a synchronous generator.

Table 4–Type Tests and Requirements Appropriate for Synchronous Generators

Section Number	Section Title
39.1	Utility Disconnect Switch
39.2	Field Adjustable Trip-points
39.3	Field Adjustable Trip-points
39.4	Field Adjustable Trip-points
39.5	Field Adjustable Trip-points, Marking
44	Dielectric Voltage Withstand Test
45.2.2	Power Factor
45.4	Harmonic Distortion
46.2	Utility Voltage and Frequency Variation Test
46.2.3	Rest Delay
46.4	Loss of Control Circuit
47.3	Short-circuit Test

A description of key aspects of these procedures is provided in the testing procedures section of this document. Separate test procedures are provided to certify non-islanding functions and non-export functions to determine the in-rush current tolerance of the distribution system to subject the device to voltage surge conditions and to verify the inverter's ability to synchronize with the distribution system.

8.9.2.1 Induction Generators

Until a standardized test procedure written specifically for induction generators is identified, PacifiCorp shall determine which of the tests described in this section are appropriate and necessary to certify the performance of the control and protection system functions of the induction generator, and how to perform them. The tests listed in Table 5 below and defined in UL 1741 shall be performed as applicable to a induction generator.

PACIFICORP
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Policy

Table 5–Type Tests and Requirements Appropriate for Induction Generators

Section Number	Section Title
39.1	Utility Disconnect Switch
39.2	Field Adjustable Trip-points
39.3	Field Adjustable Trip-points
39.4	Field Adjustable Trip-points
39.5	Field Adjustable Trip-points, Marking
44	Dielectric Voltage Withstand Test
45.2.2	Power Factor
45.4	Harmonic Distortion
46.2	Utility Voltage and Frequency Variation Test
46.2.3	Rest Delay
46.4	Loss of Control Circuit
47.3	Short-circuit Test
47.7	Load Transfer Test

8.9.3 Anti-Islanding Test

In addition to the above type tests, devices that pass the anti-islanding test procedure described in this document will be considered non-islanding for the purposes of PacifiCorp's interconnection requirements.

8.9.4 Non-Export Test

In addition to the above type tests, devices that pass the non-export test procedure described earlier will be considered non-exporting for the purposes of PacifiCorp's interconnection requirements.

8.9.5 In-rush Current Test

Generation equipment that utilizes PacifiCorp power to motor-up to speed will be tested using the procedure defined earlier to determine the maximum current drawn during this startup process. The resulting in-rush current is used to estimate the starting voltage drop.

8.9.6 Surge Withstand Capability Test

Interconnection equipment shall be tested for surge withstand capability, both oscillatory and fast transient, in accordance with the test procedure defined in IEEE/ANSI C62.45 using the peak values defined IEEE/ANSI C62.41 Tables 1 and 2 for location category B3. An acceptable result occurs even if the device is damaged by the surge, but is unable to operate or energize PacifiCorp's distribution system. If the device remains operable after being subject to the surge conditions, previous type tests related to PacifiCorp's protection and power quality will need to be repeated to ensure the unit will still pass those tests following the surge test.

8.9.7 Synchronization Test

This test verifies that the unit synchronizes within the specified voltage/frequency/phase-angle requirements. It is applied to synchronous generators and inverters capable of operating as voltage-sources while connected to the PacifiCorp system. This test is not necessary for induction generators or current-source inverters. The test will start with only one of the three parameters: 1) voltage difference between generating facility and PacifiCorp's distribution system, 2) frequency difference, or 3) phase-angle outside of the synchronization specification. Initiate the synchronization routine and verify that the generating facility is brought within specification prior to synchronization. Repeat the test five times for each of the three parameters. For manual synchronization with synch check or manual control with auto synchronization, the test must verify that paralleling does not occur until the parameters are brought within specifications.

8.10 Production Testing

As a minimum, the utility voltage and frequency variation test procedure described in UL1741 Section 68, *Manufacturing and Production Tests*, shall be performed as part of routine production (100 percent) on all equipment used to interconnect generating facilities to PacifiCorp's distribution system. This testing may be performed in the factory or as part of a commissioning test.

The following is PacifiCorp's procedure for performing commissioning. All time requirements must be met for PacifiCorp to provide the interconnection customer with timely service. Any inspections required by local government agencies must be completed and permits signed off prior to the pre-parallel date.

8.10.1 Test Results

All tests outlined below must be complete and two copies of the test reports submitted to a PacifiCorp representative a minimum of 15 working days before the requested energize date unless otherwise agreed to by PacifiCorp. All test reports require header information reflecting the equipment identification matching the one- or three-line diagrams. One-line and three-line diagrams of the facility are required to be submitted with test reports. All requirements must be met and test reports approved at least three working days before the requested pre-parallel date.

8.10.1.1 Proving Insulation

For any of the megger tests referred to below, a 2,500 volt DC megger or a hi-pot is preferred, but a 1,000 volt DC megger is acceptable.

1. All transformers connected to the primary bus and the main transformer must be meggered winding-to-winding and each winding to ground. For purposes of this document, "primary bus" is defined as the source-side bus or conductor from the primary interrupting device to the generating plant.
2. All circuit breakers and circuit switchers connected to the primary bus and at the interconnection point must be meggered in the following manner: breaker open each pole to ground, pole 1 2, pole 3 4, pole 5

6; breaker closed pole 1 ground, pole 3 ground, pole 5 ground, and if the poles are in common tank or cell, pole 1 3, pole 3 5, pole 5 1.

3. All buses and cables shall be meggered phas- to-phase and phase-to-ground.
4. The main transformer(s) and breaker(s) shall have a dielectric test performed on the insulating medium (gas or oil). This does not apply to factory-sealed circuit switcher interrupters.
5. The generator(s) must be meggered or hi-pot-tested phase-to-phase and phase-to-ground.

8.10.1.2 Proving Ratios

All ratios of transformers connected to the primary bus must be proven using either a turns ratio tester or a voltage ratios test. The main transformer must be tested on the final operating tap. This tap shall be recommended by PacifiCorp to best match transmission system operating voltages.

8.10.2 Circuit Breakers and Circuit Switchers

1. A minimum-to-trip at 70 percent or less of the nominal DC control voltage must be performed on all circuit breakers and/or circuit switchers that are operated by PacifiCorp-required relays.
2. A micro-ohm test must be performed on all circuit breakers and circuit switchers.
3. A timing test showing the time from trip initiation to main poles opening is required.
4. A timing test showing the time from close initiation to main poles closing is required.

8.10.3 Current Transformers and Current Circuits

1. A saturation check should be made on all current transformers (CTs) associated with the required PacifiCorp relays. If this is not possible, a manufacturer's curve is acceptable.
2. The ratio of all CTs must be proven either by using current (primary to secondary) or voltage (secondary to primary).
3. CT circuits must be checked for proper connections and continuity by applying primary or secondary current and reading in the relays. Each test (primary or secondary) must be performed in all combinations to prove proper connections to all phase and ground relays. Current must be applied or injected to achieve a secondary reading of five amps in each relay to ensure that no loose wiring or parallel current paths exists.
4. A single-phase burden check must be made on each phase of each current circuit feeding PacifiCorp-required relays.
5. A megger check of the total circuit with the ground wire lifted must be done to prove that only one ground exists.

8.10.4 Relays

All relays must be field tested on site to their specified settings to verify the following:

1. Minimum operating point at which relay picks up (minimum pickup).
2. Time delay at three different current test points, in integral multiples of minimum pickup that closely characterize the relay time current curve.
3. Phase angle characteristic of the directional relay.
4. Pickup points at maximum torque angle (MTA) and ± 30 degrees of MTA on impedance relays using the approved settings.
5. Slip frequency, voltage matching, phase-angle acceptance, and breaker compensation time on synchronizing relays.
6. PacifiCorp tolerances are listed below:

Table 6– PacifiCorp Relay Tolerance

Relay Type	Tolerance
Current / Voltage / Time	± 10.0 percent
Impedance / Phase Angle	± 0.05 percent
Frequency	± 0.05 percent

If a pilot relay system is required by PacifiCorp, signal level checks must be performed to PacifiCorp standards.

8.10.5 Primary Disconnect Switch

The primary disconnect switch at the point of interconnection shall be assigned a PacifiCorp number by PacifiCorp. The switch, platform, and switch number plate bracket must be constructed to PacifiCorp Engineering Standards. A switch number plate bracket shall be furnished by PacifiCorp.

8.10.6 Pre-Parallel Test Policy

Where generation has a rated output in excess of 100 kW, the entity shall reimburse PacifiCorp for the cost of performing the pre-parallel inspection.

The interconnection customer is responsible for ensuring that all relays and other protective devices are adjusted and working properly prior to the pre-parallel inspection. If problems arise with equipment during testing, the PacifiCorp protection representative may elect to cancel the test and reschedule.

All pre-parallel tests should be scheduled to begin at 9 a.m., Monday through Friday only. Functional tests shall be performed by the interconnection customer and all tests shall be observed by PacifiCorp as outlined below. The interconnection customer shall provide all test equipment and qualified personnel to perform the required tests. PacifiCorp shall be there strictly as an observer. Commissioning test forms shall be completed by the PacifiCorp representative on site at the time of the pre parallel inspection.

8.10.7 Functional Tests

The following functional tests shall be performed after the equipment has been energized, but before the generator is paralleled with PacifiCorp's system:

1. Check that each protective relay trips the appropriate generator breaker and/or main breaker. This may require injecting a signal. **Jumpering across contact on the back of the relay is not acceptable.**
2. When first energized, check that proper secondary potential is applied to all voltage and frequency relays.
3. Check the synchronizing meter, synchronizing equipment and phasing panel (if used) with the paralleling breaker closed and the generator offline. This typically requires lifting the generator leads. The equipment should show an "in-phase" condition.
4. Check the generator phase rotation. (PacifiCorp's phase rotation is A C B counterclockwise). All three phases must be checked using hot sticks with a phasing tool or a phasing panel provided by the interconnection customer. The synchronizing equipment typically checks one phase only. Phase rotation varies by area within the PacifiCorp system. Interconnection customers shall consult PacifiCorp for the correct rotation.

8.10.8 Impedance and Directional Relay Tests

Direction check all impedance and directional relays by doing the following:

1. Bring up load on the plant and/or generator.
2. Verify direction of power flow.
3. Measure the phase angle between the current and potential applied to the relay.
4. Observe the current action of the directional contacts according to the direction of power flow. Reverse either the potentials or current to prove contact operation for reverse power flow.

8.10.9 Generator Load Tests

For generators, the following load tests shall be performed after the generator picks up load:

1. Load-check all PacifiCorp required differential relays. The load current must balance to zero in all differential relays.
2. Load-check voltage restraint overcurrent relays to prove correct connection of currents and potentials.
3. The generator(s) may have to be paralleled temporarily with PacifiCorp's system to run the load tests. Permission to do this shall be given by the PacifiCorp operations representative observing the test.
4. Verify operation of the generator at 95 percent lagging power factor and at 95 percent leading power factor at rated output.
5. Verify operation of the generator at 95 percent and 105 percent of per unit voltage while delivering rated output.

6. Verify metering and telemetering to the PacifiCorp Control Center to demonstrate proper calibration and accuracy. The communication channel must be in place to verify the telemetering.

Typically, pre-parallel inspections can be performed within a normal working day. PacifiCorp shall dedicate one full work day to observe the test. If a test cannot be completed by 6 p.m., the PacifiCorp representative may cancel the remainder of the test and reschedule it. In this case the interconnection customer shall be charged another pre-parallel inspection fee.

8.11 Design Changes after Commercial Operation

Any modifications to the generator requiring PacifiCorp protective relaying and interlocks after the date of commercial operation must be reviewed and approved by PacifiCorp prior to implementing any changes. Demonstration of relay calibration, trip tests, and online tests may be required depending on the extent of the design change. Setting changes of any interconnection protection or synchronizing device must be approved by PacifiCorp with a hard copy of the changes forwarded to the designated PacifiCorp representative. Any field modification or as-built AC/DC protection and synchronizing schematics associated with any PacifiCorp-required interconnection device must be forwarded to the designated PacifiCorp representative.

8.12 Operational Log

Producers must maintain an operating log at each generating facility indicating changes in operating status (available or unavailable), maintenance outages, trip indications, or other unusual conditions found upon inspection.

8.13 Communication with PacifiCorp Grid and Field Operations

The PacifiCorp representative will provide the generation facility with the names and telephone numbers of the PacifiCorp Control Center and operations coordination personnel responsible for the PacifiCorp system at the interconnection. The generation facility will provide PacifiCorp with the names and telephone numbers of the personnel with responsibility for operating the generator.

Generation facility contacts should include at least one telephone number which can be used 24 hours a day, seven days a week. Contacts should be able to provide information on equipment status, explanation of events on the equipment, and relay target and alarm information when asked to do so by PacifiCorp personnel. PacifiCorp may choose to waive some of the communications requirements for smaller generating facilities. In addition, the generation facility should contact PacifiCorp whenever:

1. Problems with the generator are detected that could result in mis-operation of generator protection or other generator equipment.
2. The generator has tripped offline during parallel operation with the PacifiCorp system.
3. Generator equipment problems result in an outage to a portion of the PacifiCorp system.
4. The generation facility intends to initiate switching to parallel the generator(s) and the PacifiCorp system.

5. The generation facility intends to initiate switching to break the parallel interconnection between generator(s) and the PacifiCorp system.

8.14 Parallel Operation Policy

The PacifiCorp representative shall contact the PacifiCorp Control Center at least 72 hours before the pre-parallel test and shall obtain a clearance for parallel operation. The PacifiCorp representative shall provide the Control Center a drawing indicating which PacifiCorp circuit the generation facility will be connected to and which PacifiCorp-operated disconnect will be identified with a PacifiCorp-designated number. When the pre-parallel test is passed, the generator may, at PacifiCorp's discretion, be allowed to operate in parallel with PacifiCorp for testing purposes only. This should not be mistaken as an official release for parallel operation. Once testing-only permission is granted, the generator may operate in accordance with the generation operating agreement or procedures developed by the Local Area Engineer. Please review the project-specific generation interconnection and operation and maintenance agreement for details.

At the end of this period, if the interconnection customer has not received written permission from PacifiCorp to operate in parallel, the entity must isolate from PacifiCorp until written permission is received. A request for written permission to parallel shall be sent to the interconnection customer via U.S. First Class mail or via electronic mail to the distribution accounts manager (see Section 1.2.4). This shall be done after PacifiCorp has verified the following:

1. All proper contracts and documents have been executed and are in place.
2. The pre-parallel test has been passed.
3. All other outstanding issues have been resolved, including rights-of-way, deeds of conveyance, insurance verification, and operating agreements.
4. PacifiCorp has received final copies of the one-line diagram and elementary diagrams that show as-built changes made during construction, as well as a completed finalized generator data sheet (Appendix J).
5. If applicable, firm capacity performance testing of new generators cannot begin until the interconnection customer receives written permission from PacifiCorp to parallel.

8.15 General Notes

The PacifiCorp system has A C B counterclockwise rotation in most locations. The interconnection customer shall verify correct rotation with PacifiCorp.

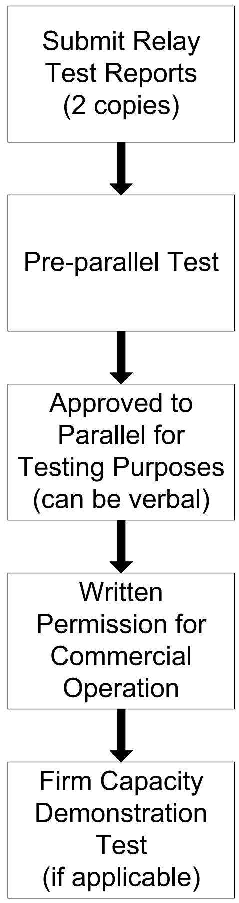
Any changes to PacifiCorp-required protection equipment or major substation equipment (transformer, breaker, etc.) must be submitted to the PacifiCorp representative for review and approval by the appropriate PacifiCorp engineer prior to the changes being made.

Routine maintenance on PacifiCorp-required protective relays and the breaker(s) must meet PacifiCorp's maintenance and test practices. After completion of these tests, test reports must be submitted to the PacifiCorp representative for review and approval by the Local Area Engineer. A PacifiCorp technical representative shall then come to the customer's facilities and reseal the PacifiCorp-required relays.

Questions shall be directed to the PacifiCorp Distribution Account Manager (see Section 1.2.4).

8.16 Simplified Flow of Pre Parallel / Parallel Test Procedure

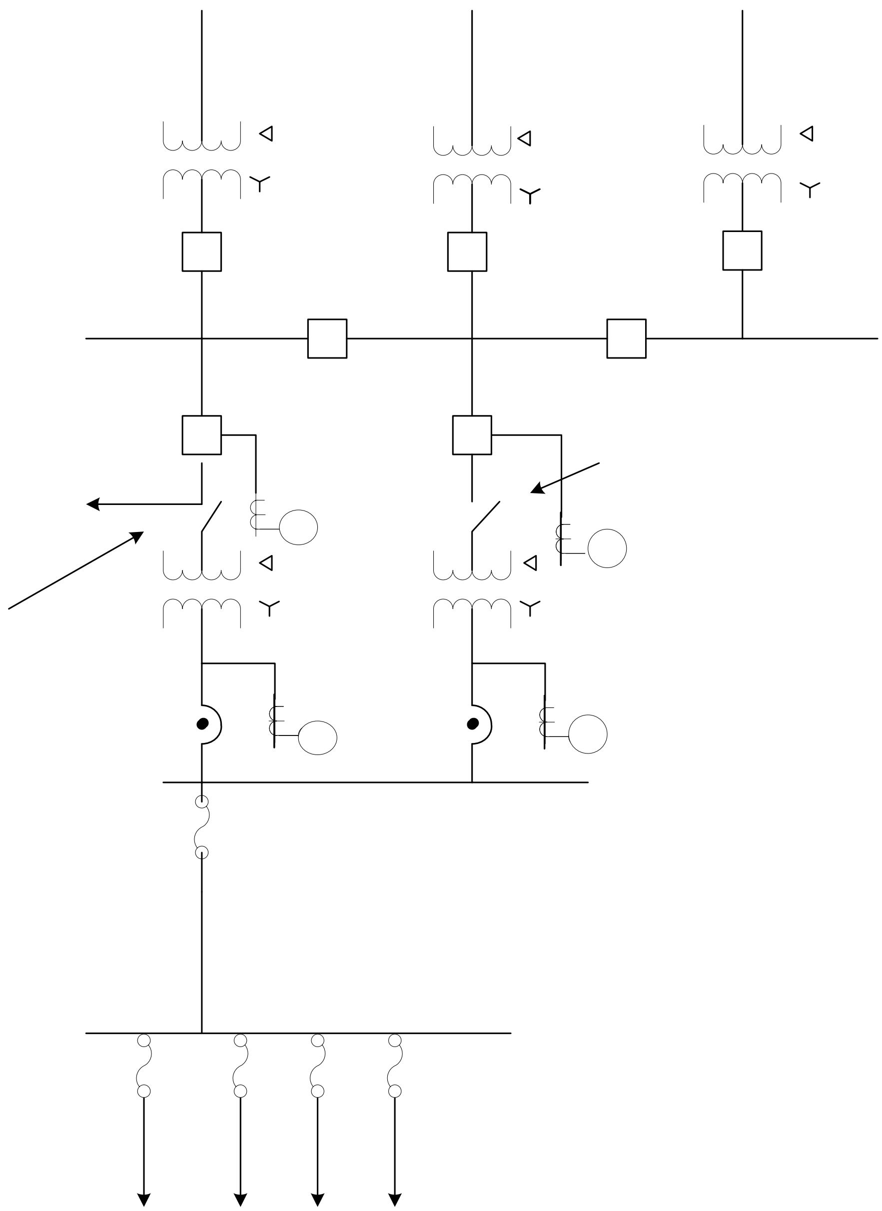
Figure 4–Pre-Parallel / Parallel Test Procedure



9 SPOT AND GRID NETWORK SYSTEM INTERCONNECTION POLICY

The interconnection of distribution-class voltage generators on networked electrical systems within PacifiCorp's service territory will comply with the most recent version of IEEE Standard 1547, *Distributed Resources*. Special attention should be paid to IEEE Standard 1547, Section 6, *Network Systems*.

Figure 5–Spot Network System



SUBSTATION TRANSFORMER

Figure 5 depicts the configuration of a typical spot network electrical system. It consists of five major components: network transformers, network protectors, network reverse power relays, high voltage transformer disconnect switch, and network protector fuse. PacifiCorp's network distribution system is 11.7KV and it is only located in Portland, Oregon.

Figure 6–Grid Network System Diagram

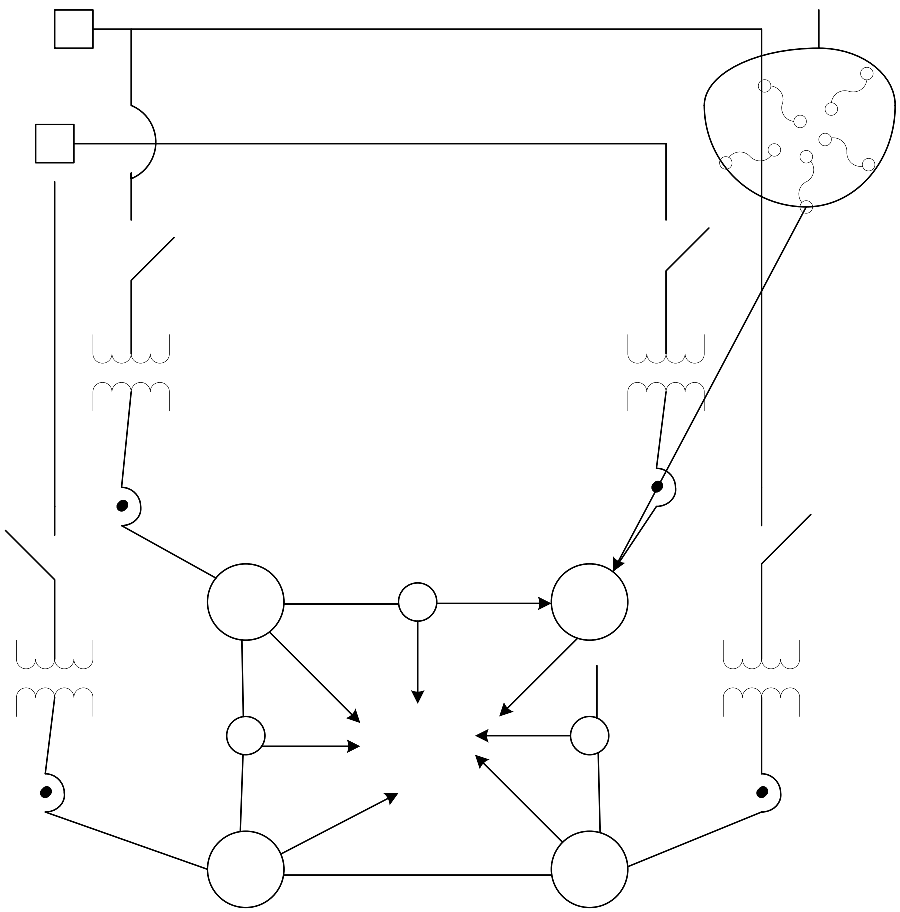


Figure 6 depicts the typical protective and control devices on a grid network system. The primary components of a grid network are as follows: network transformers, network protector reverse power relays, network protector fuses, network protectors, transformer disconnect switch, and street main secondary cable.

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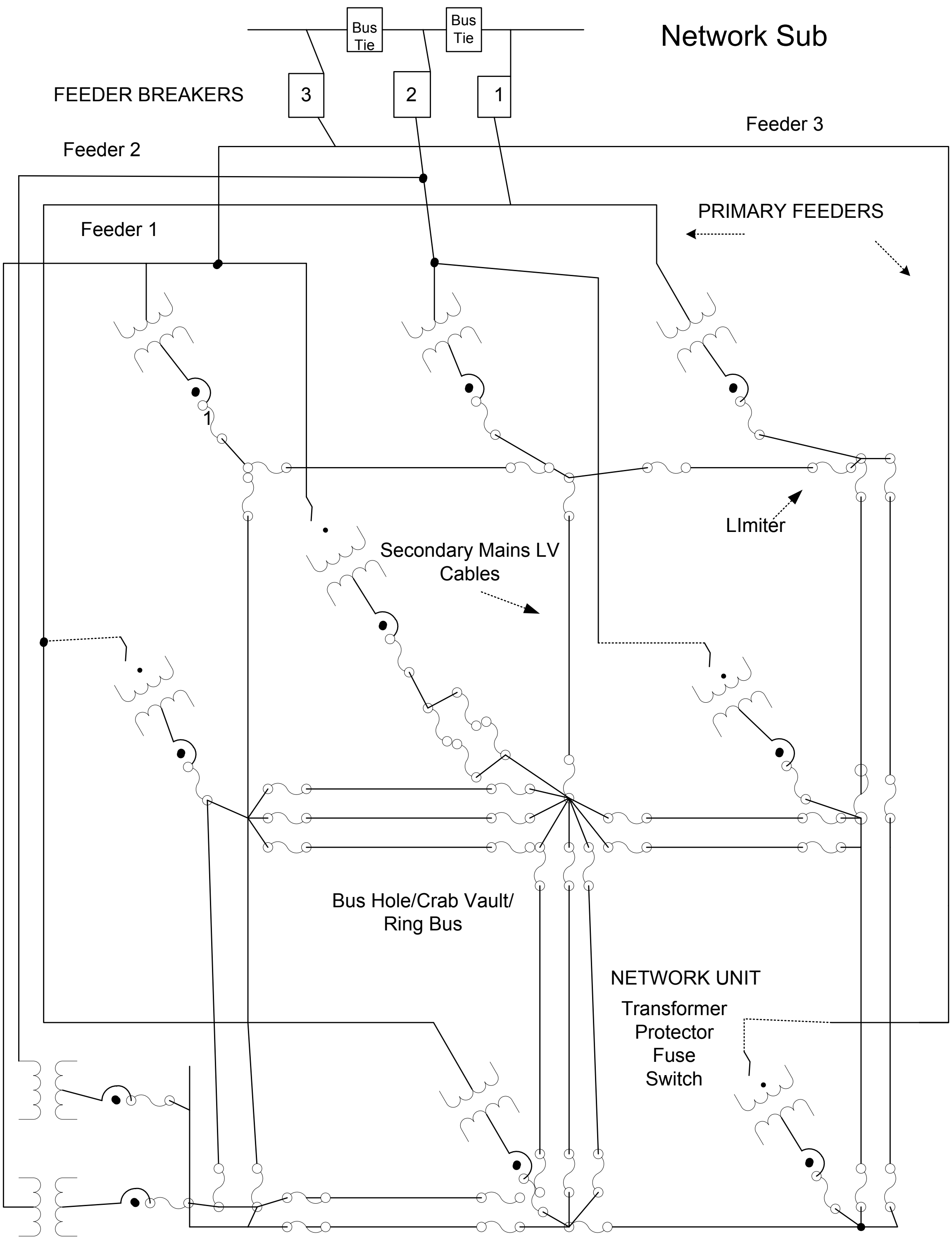
Figure 7–Typical Protective and Control Devices on a Grid Network System



Network distribution systems are the most complex distribution systems in existence. When they were designed early in the 20th century, they were intended to improve the reliability of electrical service to densely-populated urban areas. They were designed with the goal of connecting several feeders to transformers such that when one feeder goes out of service, the remaining feeders still serve the load. **Network Distribution Systems from their inception were not designed for interconnection with generators** and consequently, this presents a challenge for any applicant who wants to introduce generation into this type of electrical system.

To date, equipment manufacturers of the components of the network electrical system (shown in Figures 6 and 7) are developing and testing modifications to the equipment such that generation can be introduced into this type of circuit. The existing network system electrical components are very expensive compared to the conventional radial distribution system components which comprise the predominant portion of electrical circuits. The cost of the revised network system units will be even more expensive (likely the most expensive of any kind of electrical system components available on the market) than the conventional radial units. This means **the cost of the generation interconnection for the developer will likely be substantially more than that of a radial electrical system**.

The following are the main components of the network system:

Network Protectors: A specially designed low-voltage air circuit breaker that is controlled by its internal reverse-power network relays. With the introduction of generation, reverse current becomes more likely and thus any interconnected generation must not cause reverse current to flow through the network protector, resulting in the operation of the protector.

Network Relay: This is a relay that contains a master and a phasing relay that work in conjunction to trip the protector upon a reverse power-flow condition and to close the protector when the power flow will be into the network. No provision or arrangement has been incorporated into the design to accommodate generation.

Network Transformers: This basic building block of electrical circuits was designed in this scenario to provide for significantly enhanced circuit reliability with several three-phase circuits tied to the unit rather than the conventional technique of a single, radial, three-phase circuit. With the introduction of generation into the distribution circuits, the design of the transformer may need review and subsequent revision and alteration.

Transformer High Voltage Disconnect Switch: A three-position (open-close-ground) oil switch that connects the primary feeder to the network transformer. This is a non-load-break switch used in part to isolate the transformer from the primary distribution system.

Network Protector Fuses: The sole purpose of these fuses is to serve as a last line of protection during a fault condition. The fuses are designed to operate if the network protector fails to open during a fault. Fuses are sized at the nameplate rating of the network protector.

With the introduction of generation in the network system, the following issues may arise:

1. “Pumping” or “chattering” of network protectors. This is when the protector opens and closes repeatedly, exhibiting traits of a pump.
2. Increase of X-to-R ratios (on newer transformers) to 12 to 14 from a traditional value of 5 will necessitate at a minimum the review of relay settings and in the worst case scenario a changeout of the relay (on older models). It will be unable to be set within an

acceptable value to trip on watts since those values are not present on the device to address this condition.

3. Increasing the transformer size could alter the impedance and cause the network relay to search for values which are not present on the device. This renders it ineffective as a protective unit.
4. Phase-to-ground faults on delta-wye transformers will be harder to detect by the relays because of the impedance change. This in and of itself may necessitate a changeout of the relay. Using a different configuration transformer (wye-wye network transformer) could solve this issue, however PacifiCorp prefers not to implement this option since it is not a standard transformer connection for generation installations and would require replacing all of PacifiCorp's network transformers to wye-wye transformers. It would also reintroduce zero sequence fault currents which create difficulties for the relay protection schemes.
5. Older model network protectors do not have the fault closing capability of the newer models. In some cases, this feature will be needed, thus necessitating a changeout of the protector.
6. Low-level faults from adjacent feeders, if not cleared by the protector, could develop to become multi-phase faults. If the protector is not capable of detecting these faults because of the introduction of a DG which alters the impedance of the circuit, it will necessitate a changeout to a newer unit.
7. Network protector relays are not designed for frequency detection, thus synchronizing will not be possible until new technology is developed and the device is upgraded.
8. The introduction of DG affects the detection of arc faults thus necessitating a review of the settings for this condition. **While workers are in the vaults, sensitive ground fault protection settings must be activated.** It is possible that a changeout of the relay will be required if the settings are not available on the unit to detect and trip under arc fault scenarios.

These and other issues are addressed in detail in IEEE Standard 1547.6.

10 ACCOUNTING POLICY AND PROCEDURE

PacifiCorp will have on file within the transmission business unit (or subsequent transferee department(s)) copies of each interconnection customer's interconnection agreement and maintenance agreement for use by PacifiCorp's field personnel and accounts receivable department. These agreements will be used to create work orders with associated invoices for work performed by PacifiCorp with outside interconnection customers. These work orders and invoices will bill all entities as required by the governing FERC rules concerning generation interconnection projects.

11 GLOSSARY

A

ANSI: American National Standards Institute.

Alternating Current (AC): That form of electric current that alternates or changes in magnitude and polarity (direction) in what is normally a regular pattern for a given time period called frequency.

Ampere: The unit of current flow of electricity. This is analogous to quantity per unit of time when referring to the flow of water. One ampere is equal to a flow of one coulomb per second.

Applicable Reliability Criteria: The reliability policies established by NERC, WECC, and local reliability criteria as amended from time to time, including any requirements of the NRC which are applicable to the particular type of generator and prime mover.

Automatic: Self-acting, operated by its own mechanism when actuated by some impersonal influence as, for example, a change in current strength; not manual; without personal intervention.

Automatic Control: An arrangement of electrical controls which provide for opening and/or closing in an automatic sequence and under predetermined conditions; the switches which then maintain the required character of service and provide adequate protection against all usual operating emergencies.

Automatic Generation Control (AGC): Generation equipment that automatically responds to signals from the EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

Automatic Reclosing: A feature of some circuit breakers which allows them to reclose automatically after being tripped under abnormal conditions.

Automatic Tripping or Automatic Opening: The opening of a circuit breaker under predetermined conditions without the intervention of an operator.

Automatic Voltage Regulation (AVR): Generation equipment which automatically responds to signals from the EMS control in real time to control voltage.

B

Balanced Load: An equal distribution of load on all phases of an alternating current circuit.

Boost: To increase voltage.

Bundled Service or Bundled Utility Service: Traditional PacifiCorp service: transmission and distribution capacity for delivery, energy, and ancillary services.

Breaker: A switch which can open a circuit, usually designed for automatic operation.

C

Capacitance: Capacitance is developed when two charged or energized conductors are separated by a dielectric. An excess or deficiency of electrons is maintained on opposite plates of a charged capacitor. It may be said to be the property of an electrical circuit which opposes any change of voltage.

Capacity: The number of amperes of electric current a wire will carry without becoming unduly heated; the capacity of a machine, apparatus, or devices is the maximum of which it is capable under existing service conditions; the load for which a generator, turbine, transformer, transmission circuit, apparatus, station, or system is rated. Capacity is also used synonymously with capability.

Capacity Factor: The ratio of average load on a generating resource to its capacity rating during a specified period of time, expressed in percentages.

Circuit: A conducting part through which an electric current is intended to flow.

Circuit Breaker: A device for interrupting a circuit between separable contacts under normal or fault conditions.

Circuit Switcher: A device for interrupting a circuit between separable contacts under normal or fault conditions.

Class A Telephone Circuit: Service performance objective classification for a circuit which is non-interruptible before, during, and after a power fault condition.

Class B Telephone Circuit: Service performance objective classification for a circuit which is non-interruptible before and after a power fault condition exists.

Clearance: Permission to contact or to come in close proximity to wires, conductors, switches, or other equipment which normally might be energized at electrical, hydraulic, or pneumatic potential dangerous to human life. Conditions which must prevail before such permission can be granted are, in general, that the equipment or lines be completely isolated from all possible power sources and be tagged with properly filled out “man on line” tags.

Cogeneration: The sequential production of electricity and heat, steam, or useful work from the same fuel source.

Conductor: Material that can be used as a carrier of an electric current.

Control, Supervisory: A system for selecting control and automatic indication of remotely located units by electrical means, over a relatively small number of common transmission channels.

Control Switch: A switch controlling the circuit through circuit breakers or other switches which are magnetically operated.

Current: The part of a fluid (air, water, etc.) flowing in a certain direction. A flow of electric charge measured in amperes.

Current Transformer (CT): A transformer intended for metering, protective, or control purposes which is designed to have its primary winding connected in series with a circuit carrying the current to be measured or controlled. A current transformer normally steps down current values to safer levels. A CT secondary circuit must never be open-circuited while energized.

D

Dead-End Structure: The structure on which the last span of PacifiCorp-owned conductors terminates. Also called a landing structure. From the interconnection requester's point of view, it is sometimes called the take-off structure.

Delta-Connected Circuit: A three-phase circuit with three source windings connected in a closed delta (triangle). A closed delta is a connection in which each winding terminal is connected to the end (terminal) of another winding.

Demand: The rate at which electric energy is delivered to or by a system; normally expressed in kilowatts, megawatts, or kilovolt amperes.

Direct Access: Service election allows customers to purchase electric power and, at the customer's election, additional related services from non-utility entities known as ESPs.

Direct Current (DC): A unidirectional current in which the changes in value are either zero or so small that they may be neglected. (As ordinarily used, the term designates a practically non-pulsating current, such as the output of an electric battery.)

Disconnect: (noun) A device used to isolate a piece of equipment. A disconnect may be gang-operated (three operated together) or individually operated.

Dispatchability: Ability and availability of a generating facility to operate so that a utility can call upon it to increase or decrease deliveries of capacity to any level up to contract capacity.

Distribution Control Center: This center directs, coordinates, and implements routine and emergency switching activities on the PacifiCorp distribution system within its geographical jurisdiction.

Disturbance: Trouble (e.g., fault, sudden loss of load or generation, breaker operations, etc.) on the PacifiCorp power system resulting in abnormal performance of the system. See also System Emergency.

Droop: The slope of the prime mover's speed power characteristic curve. The speed droop, typically 5 percent, enables interconnected generators to operate in parallel with stable load division.

E

Electric Circuit: A path or group of interconnected paths capable of carrying electric current.

Electric Generator: See Generator.

Electric Substation: An assemblage of equipment for purposes other than generation or utilization, through which bulk electric energy is passed for the purpose of switching or modifying its characteristics. Service equipment, distribution transformer installations, and transmission equipment are not classified as substations.

End-Use Customer or End User: A purchaser of electric power who purchases such power to satisfy a load directly connected to the Electrical Power Grid and who does not resell the power.

Energize: To apply voltage to a circuit or piece of equipment; to connect a de-energized circuit or piece of equipment to a source of electric energy.

F

Fault Indicator: A device attached to lines which target when the current through the line exceeds the device setting.

Feeder: A circuit having as its primary purpose the distribution of electric energy.

FERC: Federal Energy Regulatory Commission.

Firm Capacity: Power committed to be available at all times during the period covered, except for forced outages and scheduled maintenance.

Forced Outage: Any unplanned outage resulting from a design defect, inadequate construction, operator error, or a breakdown of the mechanical or electrical equipment that fully or partially curtails the delivery of electricity between a load or interconnection customer's facility and the PacifiCorp power system.

Frequency: The number of cycles occurring in a given interval of time (usually one second) in an electric current. Frequency is commonly expressed in Hertz (Hz).

Fuse: A short piece of conducting material of low melting point which is inserted in a circuit and will melt and open the circuit when the current reaches a certain value.

G

Generation Facility: A plant in which electric energy is produced from some other form of energy by means of suitable converting apparatus. The term includes the generation apparatus and all associated equipment owned, maintained, and operated by the interconnection customer.

Generator: The physical electrical equipment that produces electric power. Sometimes used as a brief reference to an interconnection customer.

Grid-Critical Protective Systems: Protective relay systems and Remedial Action Schemes that the may have a direct impact on the ability to maintain system security.

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

Ground: A term used to refer to the earth as a conductor or as the zero of potential. For safety purposes, circuits are grounded while any work is being done on or near a circuit or piece of equipment in the circuit; this is usually called protective grounding.

Ground Bank: A secondary transformer bank installed on delta-connected winding to provide a path to ground for relaying purposes.

Ground Fault: An unintentional electric current flow between one or more energized conductors and the ground.

Ground Potential Rise: A calculated value of the highest expected voltage due to a line-to-ground fault at or near the station (power switchyard). The value is calculated as follows:

GPR = 1.2 (DC Transient Factor) x 1.4. x Ground Fault Return Current (rms) x Ground Resistance

H

Hertz (Hz): The term denoting cycles per second or frequency; named after Heinrich Hertz, the pioneering German scientist who performed research on electrical power.

I

IEC: International Engineering Consortium.

IEEE: Institute of Electrical and Electronic Engineers.

Inductance: The property of an electric circuit which produces a voltage by electromagnetic induction when the current in the circuit changes or varies. It opposes any change of circuit current.

Induction Generator: Typically an induction motor that is being driven by a prime mover at a speed which is faster than the synchronous mechanical speed to generate electric power. It typically depends on the host system for its excitation and speed regulation.

Interconnection Agreement (IA): An agreement between the utility and the interconnection customer specifying and outlining the terms and conditions of the interconnection of the generators to PacifiCorp's electrical system.

Interconnection Customer: An entity interconnected to the PacifiCorp power system which has generation facilities (including back-up generation in parallel) on its side of the point of interconnection with the PacifiCorp power system.

Interconnection Facilities: All means required and apparatus installed to interconnect and deliver power from a load or interconnection customer facility to the PacifiCorp power system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment, such as equipment required to protect: 1) the PacifiCorp power system and the load or interconnection customer from faults occurring at the load or generation, and 2) the load or generation facility from faults occurring on the PacifiCorp power system or on the systems of others to which the PacifiCorp power system is directly or indirectly connected. Interconnected facilities also include any necessary additions and reinforcements by PacifiCorp to its system required as a result of the interconnection of a facility to the PacifiCorp power system.

Interconnection Study Agreement (ISA): An agreement between the interconnection customer and PacifiCorp specifying what is to be done in the engineering interconnection study to interconnect the generator to PacifiCorp's system. This agreement specifies not only the items to be studied but the timeframe in which the study will be completed and the report results submitted to the applicant.

Interconnection Study: Those studies performed in conjunction with an interconnection request to determine the facilities needed to interconnect the load or interconnection customer in accordance with applicable reliability requirements.

Interrupting Capacity: The amount of current a switch or circuit breaker can safely interrupt.

Interruption: A temporary discontinuance of the supply of electrical power.

K

Kilovolt (kV): 1,000 volts.

Kilovolt Ampere (kVa): The product of kilovolts times amperes. Used to refer to high voltage alternating current systems.

Kilovolt Ampere Reactive (kVar): A measure of reactive power which is required to regulate system voltage.

Kilowatt (kW): An electrical unit of power which equals 1,000 watts.

Kilowatthour (kWh): 1,000 watts of energy supplied for I hour. A basic unit of electric energy equal to the use of I kilowatt for a period of I hour.

L

Lagging Power Factor: Occurs when reactive power flows in the same direction as real power. Stated with respect to the generator, lagging power factor occurs when the generator is producing vars.

Leading Power Factor: Occurs when reactive power flows in the opposite direction to real power. Stated with respect to the generator, leading power factor occurs when the generator is absorbing vars.

Line Losses: Electrical energy converted to heat in the resistance of all transmission and/or distribution lines and other electrical equipment (i.e., transformers) on the system.

Load-Only Entity or Customer Load: An entity interconnected to the PacifiCorp power system at a transmission or distribution voltage level which does not have generation of its own in parallel with the PacifiCorp power system and is not interconnected with any source of generation other than PacifiCorp's.

Log: A computer file, book, or loose leaf sheets for recording all station operations, clearances, readings, ratio reports, and other pertinent active daily data.

M

Maximum Torque Angle (MTA): The phase angle between the relay measured quantities at which the relay is the most sensitive.

Metering Services: Consists of removal, ensuring of meter design specifications, installation, calibration, and ongoing testing and maintenance of meters.

Meter Service Agreement (MSA): The agreement issued by PacifiCorp concerning meter services.

Megawatt (MW): 1 million watts.

Megger: An ohm meter device used to measure the ability of insulation to withstand voltage, as well as measuring the insulation resistance. A poor megger test would mean that the insulation is breaking down.

N

Nameplate Rating, Facility: Output rating information appearing on a generator nameplate or other electrical device, in accordance with applicable industry policies.

NEMA: National Electrical Manufacturers Association.

NERC: North American Electric Reliability Council or its successor.

Net Energy Output: The generation facility's gross output in kilowatt hours, less station use, to the point of delivery into the PacifiCorp power system.

Net Sale: The generation facility's gross output, in kW and kWh, less station use, to the point of delivery into the PacifiCorp power system.

Network System: An electrical distribution system designed with special transformers and protection devices such that more than one radial three-phase circuit can be connected to serve load.

Network Protector: A special electrical device connected to a network transformer which trips load on reverse flowing current.

Network Transformer: A special transformer designed to accommodate the connection of more than one three-phase circuit to allow for enhanced reliability.

Network Relay: A special relay connected to a network transformer designed to trip the unit of line for excess fault currents.

Neutral: The common point of a star-connected transformer bank, a point which normally is at zero potential with reference to the earth.

No-Sale: The interconnection customer desires to operate in parallel and not sell power to PacifiCorp.

O

Ohm: The unit of resistance of an electric circuit.

One-Line Diagram: A diagram in which several conductors are represented by a single line and various devices or pieces of equipment are denoted by simplified symbols. The purpose of such a diagram is to present an electrical circuit in a simple way so that its function and configuration can be readily grasped.

Operating Procedures: Policies and procedures governing the operation of the transmission grid as PacifiCorp, the WSCC, or the NERC may from time to time develop as applicable to the particular type of generator and prime mover.

Operational Control: The rights of PacifiCorp to operate their transmission lines, facilities, and other electric plant equipment affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting applicable reliability criteria and policies.

Outage: A condition existing when a line or a substation is de-energized.

Output: The energy delivered by a generation facility during its operation.

Overload: A load in amperes greater than an electric device or circuit is designed to carry.

Overvoltage: Voltage higher than that desired or higher than that for which the equipment in question is designed.

P

PacifiCorp Control Center: The PacifiCorp location, manned 24 hours a day, which has been assigned operational jurisdiction over a load or interconnection customer's substation.

Parallel: (verb) To connect electrically a generator or energized source, operating at an acceptable frequency and voltage, with an adjacent generator or energized system, after matching frequency, voltage, and phase angle.

Parallel Operation: As used in this manual, the operation of a non-utility owned generator while connected to the utility's grid. Parallel operation may be required solely for the interconnection customer's operating convenience or for the purpose of delivering power to the utility's grid.

Peaking: Operation of generating facilities to meet maximum instantaneous electrical demands.

Permissive Overreach Transfer Trip Scheme (POTTS): A very secure line protection scheme for insuring that a fault is within the protected line section. It requires the presence of both a trip signal from a remote terminal and a trip signal from the local relay before tripping the local breaker.

PacifiCorp Power System: The electric transmission and distribution wires, and their related facilities owned by PacifiCorp.

Point of Interconnection (POI): The point where the load or interconnection customer's conductors or those of their respective agents meet the PacifiCorp power system (point-of-ownership change).

Potential Transformer (PT): A transformer intended to reproduce in its secondary circuit, in a known proportion, the voltage of the primary circuit; also known as a voltage transformer.

Power: The time rate of transferring or transforming energy.

Power Factor (PF): The ratio of real (MW) power to apparent power (MVA). Power factor is the cosine of the phase angle difference between the current and voltage of a given phase.

Power Purchase Agreement (PPA): An agreement/contract between the utility and interconnection customer whereby the amount for the purchase of power has been determined and is contractually binding on both parties.

Primary: Normally considered as the high-voltage winding of a substation or distribution transformer; any voltage used for transmission of electric power in reasonably good-sized blocks and for some distance, as contrasted with low voltage for the immediate supply of power and light locally, such as the distribution within a building. The lowest voltage considered as a primary voltage is 2.4 kV although this is also used for some heavy-power requirements over short distances.

Primary System: A system of alternating current distribution for supplying the primaries of transformers from the generating station or distribution substation.

Protection: All of the relays and other equipment used to open the necessary circuit breakers to clear lines or equipment when trouble develops.

Protective Relay: A device whose function is to detect defective lines or apparatus, or other power system conditions of an abnormal or dangerous nature, and to initiate appropriate control circuit action.

Pumping: A condition present on a network protector whereby the device turns on and off very quickly due to deviant circuit conditions. These conditions can be introduced with the interconnection of generation on the circuit. Pumping is to be avoided on the protector so that it can properly perform its protective function.

R

Reactance: In an alternating current circuit, the opposition to the flow of current attributable to the inductance and capacitance of the circuit.

Reactive Component of Current: That part of a current that does no useful work because its phase is 90 degrees leading or lagging the voltage.

Reactive Load: In alternating current work, a load whose current is not in phase with the voltage across the load.

Reactor: A coil with no secondary winding provided. The primary use is to introduce inductance into the circuit for purposes such as starting motors, paralleling transformers, and controlling current. A current limiting reactor is a reactor for limiting the current that can flow in a circuit under short circuit conditions.

Reclose: To again close a circuit breaker after it has opened by relay action.

Recloser: A protective device designed to: 1) sense overcurrents, 2) time and interrupt the overcurrent according to a preset characteristic, and 3) reclose to test and possibly reenergize the line after a specified time interval.

Remedial Action Scheme (RAS): Protective systems that typically utilize a combination of conventional protective relays, computer based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events; also refers to details of RAS logic and any special requirements for arming of RAS schemes or changes in RAS programming that may be required.

Remote Station Alarms: Alarms received at an attended location from unattended stations or plants.

Remote Terminal Unit (RTU): Remotely located equipment used for collecting data and/or for supervisory control via communication channel.

Residual Current: The current which flows in the neutral or wye-connected current transformers when the current in the three phases of a line are unbalanced.

Resistance: Anything placed or already located in an electric circuit which opposes the flow of electric current.

Resistor: A device whose primary purpose is to introduce resistance into an electric circuit. An adjustable resistor is one so constructed that its amount of resistance can be readily changed.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Retail Service: Electric sales to PacifiCorp's end-use or retail customers. Such service is regulated by the jurisdictional state regulatory agencies.

S

Schematic: A diagram showing the essential features of a piece of equipment or a control system.

Secondary: The winding of a transformer which is normally operated at a lower voltage than the primary winding.

Secondary Distribution System: A low-voltage alternating current system which connects the secondaries of distribution transformers to the consumer's services.

Self-Excited: A term to describe an electric machine in which the field current is secured from its own armature current. In the case of induction generators, it refers to the condition in which the induction generator is separated from its normal excitation source and is unintentionally excited by the power factor correction capacitors in the vicinity.

Separately-Excited: Use of an exciter for sending current through the field windings of an electric machine in place of taking the field current from its own armature current.

Service Reliability: The time an entity or group of entities is served compared to the amount of time the entity or entities are without service over a given time period.

Service Restoration: The switching procedure a system operator directs or executes to restore services to entities following an outage.

Setting: The values of current, voltage, or time at which a relay is adjusted.

Single-Phase Circuit: A circuit in which all current can be represented by only one regular sine-wave pattern. Differs from a three-phase circuit, where when all circuit current is plotted, it produces three regular sine-wave patterns 120 electrical degrees apart.

Special Facilities: Those additions and reinforcements to the PacifiCorp power system which are needed to accommodate the receipt and/or delivery of energy and capacity from and/or to the entity's facility(ies), and those parts of the interconnection facilities which are owned and maintained by PacifiCorp at the entity's request, including metering and data processing equipment.

Standby Capacity: The lesser of: 1) net generation capacity, 2) connected loads to generator, or 3) 80 percent of main switch rating.

Star-Connected Circuit (Wye-Connected Circuit): A term applied to the manner in which a motor's windings or a transformer's windings are connected, (i.e., star-connected armature having one end of each of the coils connected to a common junction). A star-connected transformer is one in which the primaries and secondaries are connected in a star grouping.

Station Use: Energy used to operate the generating facility's auxiliary equipment. Auxiliary equipment includes, but is not limited to: forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, power plant lighting, fuel handling systems, control systems, and sump pumps.

Step-Down Transformer: A transformer in which the secondary winding has fewer turns than the primary, so that the secondary delivers a lower voltage than is supplied to the primary.

Step-Up Transformer: A transformer in which the secondary winding has more turns than the primary, so that the secondary delivers a higher voltage than is applied to the primary.

Supervisory Control: A system by which equipment is operated by remote control at a distance using some type of code transmitted by wire or electronic means.

Surplus Sale: The generator's gross output, in kW and kWh, less any plant load and transformation and transmission losses, delivered to the PacifiCorp system.

Switch: A device for making, breaking, or changing the connections in an electric circuit.

Switch, Air: A switch in which the arc interruption of the circuit occurs in the air.

Switch, Alarm: A form of auxiliary switch which closes the circuit to a bell or other audible signaling device upon automatic opening of the circuit breaker or other apparatus with which it is associated.

Switch, Auxiliary: A switch actuated by some main device such as a circuit breaker for signaling, interlocking, or other purpose.

Synchronism: The condition across an open circuit wherein the voltage sine wave on one side matches the voltage sine wave on the other side in frequency and without phase angle difference.

System: The entire generating, transmitting, and distributing facilities of an electric utility.

System Emergency: Conditions beyond the normal control that affect the ability of the control area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.

System Protection Facilities: The equipment required by the utility to protect: 1) the PacifiCorp power system from faults occurring at a load or interconnection customer' facility, and 2) the load or interconnection customer's generating facility from faults occurring on the PacifiCorp power system or on the system of others to which it is directly or indirectly connected.

T

Telephone Working Limit: A voltage potential of 300 V or less, so personnel can work on the telephone cable without rubber gloves.

Telemetering: Measurement with the aid of a communication channel that permits power metering measurements to be interpreted at a distance from the primary detector.

Transfer Trip (TT): A form of remote trip in which a communication channel is used to transmit the trip signal from the relay location to a remote location.

Transformer: An electric device without continuously moving parts in which electromagnetic induction transforms electric energy from one or more other circuits at the same frequency, usually with changes in value of voltage and current.

Transformer Efficiency: Ratio of the electric power of the current going into a transformer to the power of the secondary circuit from the transformer.

Transformer Loss: The difference between the input power to a transformer and the output power of the transformer.

Transformer Ratio: The ratio of the voltage secured from a transformer to the voltage supplied to that transformer.

Transmission Line: A line used for electric power transmission. Distinguished from a distribution line by voltage. Lines rated 46 kV and higher are transmission lines.

Transmission Control Center: This center implements switching operations on the PacifiCorp transmission system within a specific geographical area.

U

UL: Underwriters Laboratories.

Undervoltage Protection: Upon failure or reduction of voltage, the protection device interrupts power to the main circuit and maintains the interruption.

Undervoltage Release: Upon failure or reduction of voltage, the protective device interrupts power to the main circuit but does not prevent again completing the main circuit upon return to voltage.

Unity Power Factor: A power factor of 1.000 which exists in a circuit wherein the voltage and current are in phase. There are no vars in this condition, only watts.

V

Var: A unit of measurement of reactive power. It is an expression of the difference between current and voltage sine waves in a given circuit; short for volt amps reactive.

VA2 = (Watts)2 + (Vars)2

Volt: The unit of electrical pressure similar to the pounds per square inch pressure on a steam gauge.

Volt Ampere: A unit of apparent power in an alternating current circuit. Equal to the product of volts and amperes without reference to the phase difference, if any. At unity power factor, a volt ampere equals a watt. Whenever there is any phase difference between voltage and current, the true power in watts is less than the apparent power in volt amperes.

Voltage Drop: The difference in voltage level between one point and another in a circuit (see line voltage drop).

Voltage Loss: The drop of potential in an electric circuit due to the resistance and reactance of the conductor. This loss exists in every circuit.

Voltage Ratio of Transformer: The ratio of the effective primary voltage to the effective secondary voltage of a transformer.

Voltage Transformer: See potential transformer.

W

Watt: A unit of electric power.

Watts AC = volts x amperes x power factor (single phase circuits).

Watt Hour: A measure of electric power. The power of one watt used for one hour.

Watt Hour Meter: An electrical measuring instrument which indicates power in watt hours.

WECC: Western Systems Coordinating Council or its successor.

Wholesale Customer: A person wishing to purchase energy and ancillary services at a bulk supply point or a scheduling point for resale.

Wholesale Sales: The sale of energy and ancillary services at a bulk supply point or a scheduling point for resale.

Wholesale Service: Electric sales to wholesale customers for resale. Such service is regulated by FERC.

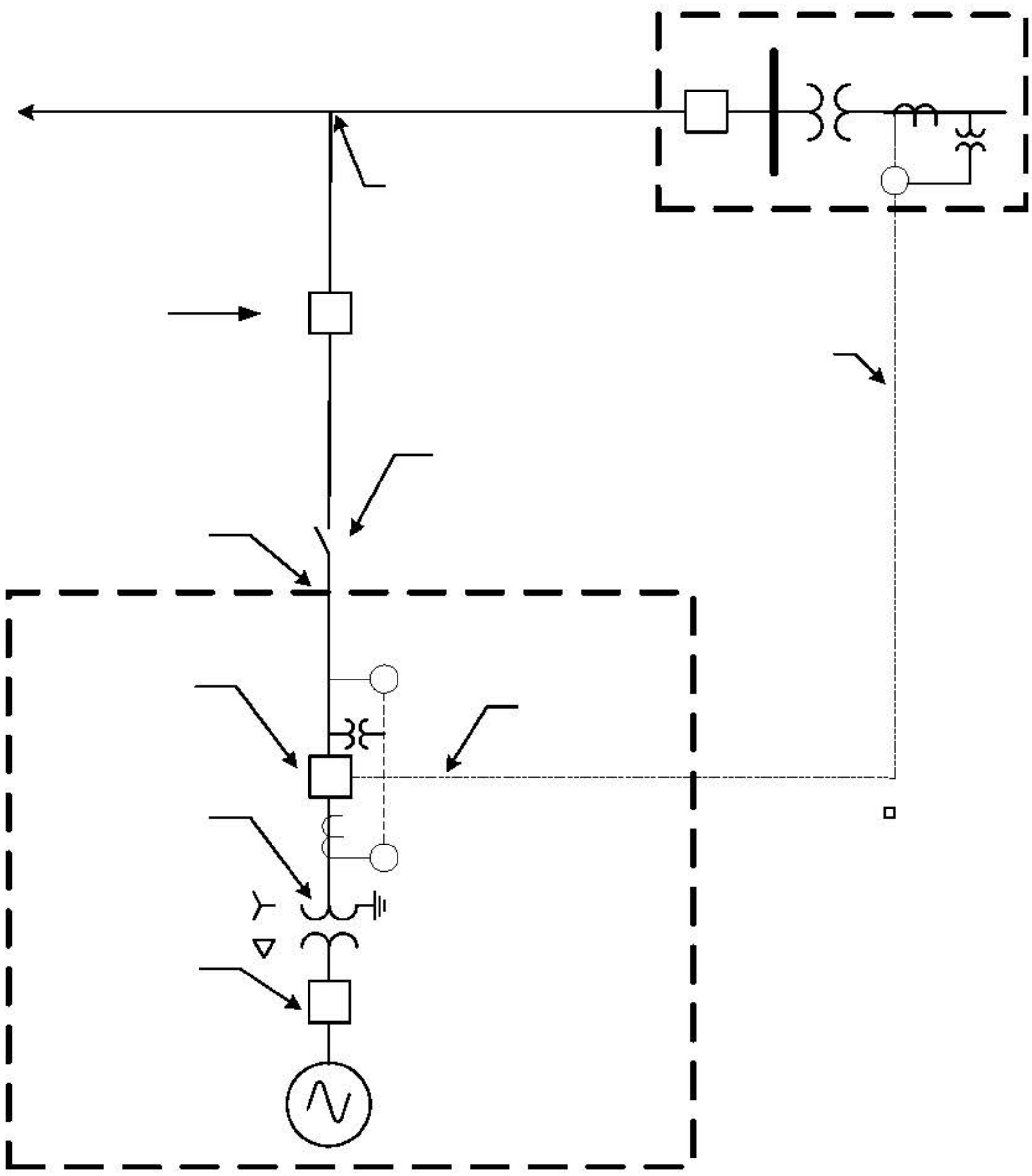
"Wye"-Connected Circuit: A three-phase circuit which is star-connected, meaning the windings of all three phases have one common connection which may be connected to ground.

CONTACTS
For Reference Documents and Information

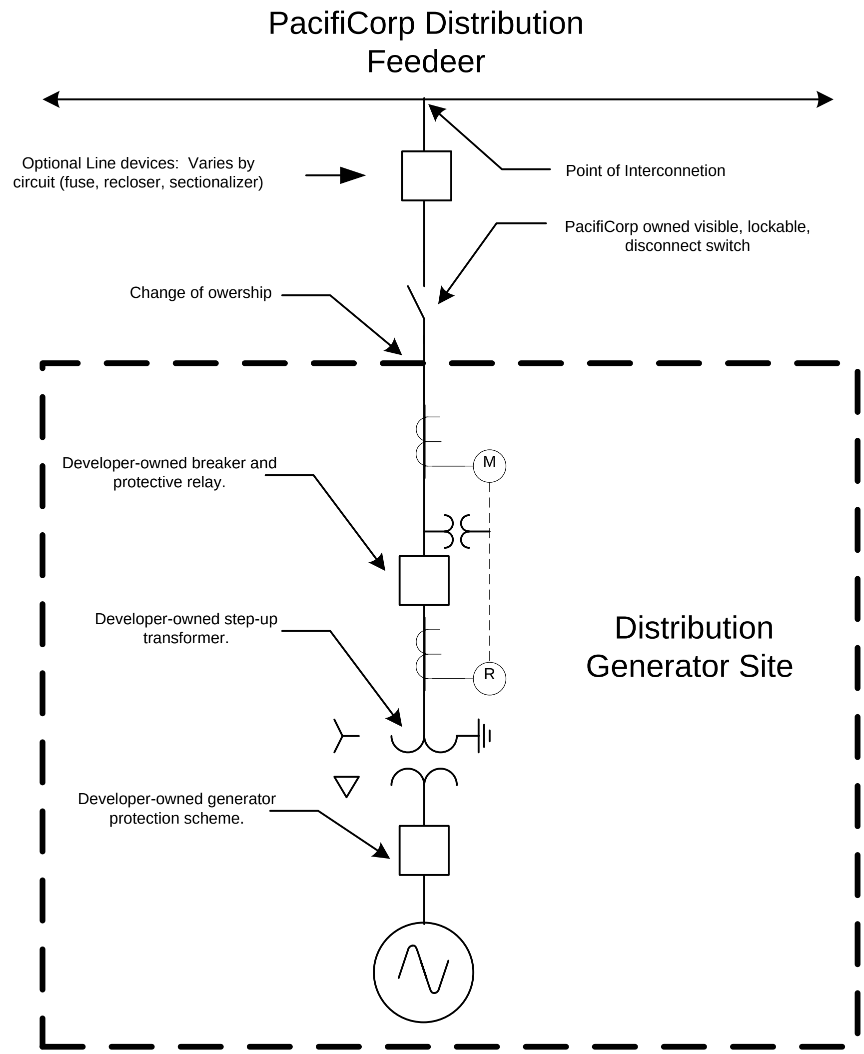
Entity	Example Documents	Who To Contact
California Public Utilities Commission (CPUC)	Retail Tariffs Electric Rules	Energy Division California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102 (415) 703-2782 http://nic.cpuc.ca.gov/
Idaho Public Utilities Commission (IPUC)	Retail Tariffs Electric Rules	Idaho Public Utilities Commission P.O. Box 83720 Boise, ID 83720-0074 (208) 334-0300 http://www.puc.state.id.us
Oregon Public Utilities Commission (OPUC)	Retail Tariffs Electric Rules	Oregon Public Utilities Commission 550 Capitol St. NE Salem, Oregon 97310-1380 (503) 378-6611 http://www.puc.state.or.us/
Utah Public Service Commission (UPSC)	Retail Tariffs Electric Rules	Utah Public Service Commission Heber M. Wells Building, 4th Floor P.O. Box 160 East 300 South Salt Lake City, UT 84111 http://www.psc.state.ut.us
Washington Utilities and Transportation Commission (WUTC)	Retail Tariffs Electric Rules	Washington Utilities & Transportation Commission P.O. Box 47520, Mail Stop: FY-11/7250 Olympia, WA 98504-7250 (360) 753-6423 http://www.wutc.wa.gov
Wyoming Public Service Commission (WPSC)	Retail Tariffs Electric Rules	Wyoming Public Service Commission 2515 Warren Avenue Hansen Bldg., Suite 300 Cheyenne, WY 82002 (307) 777-7427 http://www.psc.state.wy.us/index.html
Federal Energy Regulatory Commission (FERC)	Code of Federal Regulation Orders	Federal Energy Regulatory Commission Public Reference & Files Maintenance Branch 888 First Street, NE. Room 2-A Washington, DC 20426 (202) 208-1371 http://www.ferc.fed.us/
North American Electric Reliablilty Council (NERC)	National Reliability Standards	North American Electric Reliability Council Princeton Forrestal Village, 116-390 Village Boulevard Princeton, New Jersey 08540 (609) 452-9060 http://www.nerc.com
PacifiCorp (PPW)	Tariffs Standards Interconnection Handbook	Pacificorp, Inc. 825 NE Multnomah Portland, Oregon 97232 (503) 813-5731 http://www.pacificorp.com
Western Systems Coordinating Council (WSCC)	Western Reliability Standards	Western Systems Coordinating Council 540 Arapeen Drive. Suite 203 Salt Lake City, UT 84108 (801) 582-0353 http://www.wscc.com

NOTE: This list is modified periodically. Consult your local PacifiCorp representative for the most current version.

Distribution Generator Template with Transfer Trip



Distribution Generator Template



Electric Primary Service Requirements

PURPOSE

The purpose of this standard is to provide the requirements for the interconnection of electric customers served directly via the PacifiCorp distribution system. This standard is to be used for all existing primary service customers as well as all new customers.

DEFINITION OF TERMS

Primary Protective Device: That device that will detect faults within the customer's facilities and automatically operate to separate the customer from the PacifiCorp distribution grid.

Primary Service (PS) Customer: A customer receiving primary services voltage from PacifiCorp at a distribution voltage level (2.4 kV through 21 kV).

Coordination: The ability of the appropriate protective device to detect and operate to a clear fault on the electric system prior to another protective device operating.

CUSTOMER RESPONSIBILITIES

The PS Customer must not have an adverse impact upon the service reliability of the other PacifiCorp customers that are served via the same distribution system. It is the responsibility of **all** PS customers to install a satisfactory primary protective device and adequately coordinate with the appropriate PacifiCorp source-side protective device. Satisfactory coordination is defined as that which meets the criteria outlined in PacifiCorp's protection standards. The PS is responsible for owning, operating, and maintaining all required protective equipment.

PROCEDURES

Before the specific primary service installation can be approved, the customer is responsible for providing all the information necessary for PacifiCorp to determine the interconnection requirements. This includes, but is not limited to:

- One-line diagrams, meter and relay diagrams, control diagrams, and equipment specifications illustrating the interconnection design.
- All relay information (if applicable) including manufacturer, style, types, ranges, and settings for PacifiCorp-required relays.
- Projected electrical demand information.

Prior to energizing the applicant's new facility, the following activities must be completed:

- Test reports for the device and relays must be provided to PacifiCorp 10 days prior to the scheduled energization date so that there is sufficient time for review and the completion of any needed modification, including PacifiCorp approval.

- The customer must have a documented maintenance program for the protective devices and relays.
- Protective relay settings or fuse sizes must be approved by PacifiCorp.
- A pre-energization by PacifiCorp personnel must be performed to verify the proper operations of the customer's equipment.

PROTECTIVE DEVICE REQUIREMENTS

Fused cutouts are acceptable as long as satisfactory coordination can be obtained between the fuse and the PacifiCorp source-side protective device for both ground and phase faults. It becomes the customer's responsibility to protect their facility against single-phasing problems that arise due to the operation of one fuse.

If satisfactory coordination cannot be obtained using fuses, a three-phase interrupting device will be required. Reclosers, interrupters, or breakers are acceptable devices for this application. If a protective device is required to be installed on the customer's service by PacifiCorp because the customer's protective device will not coordinate with the PacifiCorp source-side device, it will be installed as Special Facilities. If the protective device is installed on the distribution circuit serving the customer for reasons other than those stated above, it will be at PacifiCorp's expense.

> **Note:** Sectionalizers are not an acceptable substitute for either fuses or a three-phase protective device because their operation inherently subjects other PacifiCorp customers to an outage for problems in the PS customer's facilities.

If electrically operated breakers and protective relays are used, it is preferable that the customer install a battery system. For economic reasons, the customer may prefer to use capacitive tripping. This may be allowed but the customer must install an alarm system to identify when the capacitor voltage falls below a predetermined set level. Spare capacitors must also be kept on hand for immediate exchange.

PROTECTIVE RELAYS

If relays are installed by the customer as part of the primary protection, they must meet the following criteria:

- Relays installed must be approved by PacifiCorp prior to their installation. If the relay being presented for approval is one not currently on the approved relay list, complete relay information, including instruction books and operating characteristics, should be provided to the PacifiCorp Transmission Account Manager.
- Phase and ground relays must be installed to protect against both three-phase and line-to-ground faults within the customer's facilities.
- If microprocessor-based three-phase devices are used, multiple units of other backup devices will be required so that the ability for the customer to detect a fault is not dependent on a single relay.

EXISTING FACILITIES

The requirement for the customer to maintain coordination and provide complete protection of their facilities refers to existing PS customers as well as new or upgraded installations. The coordination of these customers should be reviewed when performing a protection review on the circuit feeding the PS customer.

A common issue that arises when a customer owns facilities that were previously purchased from PacifiCorp is the requirement to provide both phase and ground coordination that differs from what existed when PacifiCorp owned the facilities. This is required because:

1. Jurisdictional state utility commissions typically require that a PS customer is responsible for ensuring that other PacifiCorp customers are not exposed to unnecessary service interruptions due to problems in the PS customer's facility. If both phase and ground coordination is not maintained, problems on the customer's equipment has a higher probability of affecting other PacifiCorp customers.
2. The customer assumed the responsibility of maintaining adequate coordination in order to qualify for the primary rate.
3. When PacifiCorp owned the system, the company accepted the exposure risk in exchange for the lower cost fuse installation. This cost savings was spread among all of PacifiCorp's ratepayers. When the PS customer purchases the system, all cost savings of a fused installation would be captured by the PS customer while other PacifiCorp customers would inappropriately continue to bear the risks associated with additional exposure.

NEW FACILITIES

Occasionally, the customer may indicate that it will not be possible to coordinate their main protective device with the current PacifiCorp source-side device. PacifiCorp should review the source-side device settings to determine if they can be increased. It may be possible to modify the settings with little work and no reduction in reliability and thereby provide increased coordination margin for the PS customers. This will be determined by PacifiCorp on a case-by-case basis.

If the PacifiCorp source-side device settings cannot be modified or the customer still cannot coordinate, it remains the customer's responsibility to coordinate with the PacifiCorp source-side device, with the costs involved completely borne by the PS customer. Costs should include all equipment modifications and will include Special Facility charges with the appropriate Cost of Ownership payment. In addition, any changes to the distribution system's protection must not be detrimental to the other customers on the system.

LOCATION OF PRIMARY PROTECTION

The customer's primary protective device should ideally be installed at the service delivery point designated by PacifiCorp. The service delivery point for PS customers is at or near the customer's property line. Due to the design of the customer's facility, it may not be

Generation Interconnection for Distribution Systems

cost effective for the customer to install the equipment right at the property line. The customer's facility design will most often have the main protective device located adjacent to the main transformer or distribution switchgear. Any additional PacifiCorp facilities installed to allow for this alternative placement will be installed as Special Facilities.

Under some circumstances, the customer can be permitted to install the primary protective device in a location which places some exposure from the customer facilities onto the PacifiCorp system. While it is difficult to determine how much exposure is acceptable, the following guidelines provide a uniform approach with some flexibility for addressing unique situations:

Overhead: Approximately 50 feet of conductor between the change-of-ownership point and the PS customer's primary protective device is acceptable if the route is free of potential hazards (especially trees).

Underground: The PS customer may be required to install a splice box with load-break elbows at the property line. This arrangement will allow the customer's facilities to be disconnected from the PacifiCorp system without necessitating a shutdown affecting other PacifiCorp customers. Approximately 100 feet of underground conductor between the point-of-ownership change and the customer's main protective device is acceptable. Since the main exposure on underground projects is due to splices and terminations, continuous runs of cable of lengths slightly in excess of 100 feet may be acceptable. This will be determined on a case-by-case basis with the intent to minimize the exposure to the PacifiCorp distribution system.

If the design of the customer's facility is such that the aforementioned coordination and location criteria cannot be met, PacifiCorp will install, own, and maintain an appropriate protective device at or near the change-of-ownership point. The cost of this installation will be borne by the PS customer under a Special Facilities Agreement. This option is only acceptable after every attempt has been made to work with the customer to find a solution which does not require this additional device.

MAINTENANCE REQUIREMENTS

The customer is responsible for maintaining the protective equipment in a serviceable and generally accepted manner. PacifiCorp has the right to request that the customer provide proof of maintenance activities upon request. If the PS customer does not perform appropriate maintenance or fails to provide records to PacifiCorp which documents appropriate maintenance activities, PacifiCorp may terminate service pursuant to applicable state commission rules and regulations. Moreover, if a problem with the PS customer's facilities has a detrimental affect on PacifiCorp or other customers, the PS customer will be considered liable.

In the event that there is a failure or problem with any of the interconnecting equipment, the PS customer must make any corrections or repairs to their facility deemed necessary by PacifiCorp to maintain adequate reliability. The PS customer may be required to take such actions as PacifiCorp deems necessary or appropriate to prevent any recurrence of the problem.

The PS customer must contact PacifiCorp prior to making any changes to their primary protective device. PacifiCorp must approve all changes before they are made to ensure that adequate coordination is maintained.

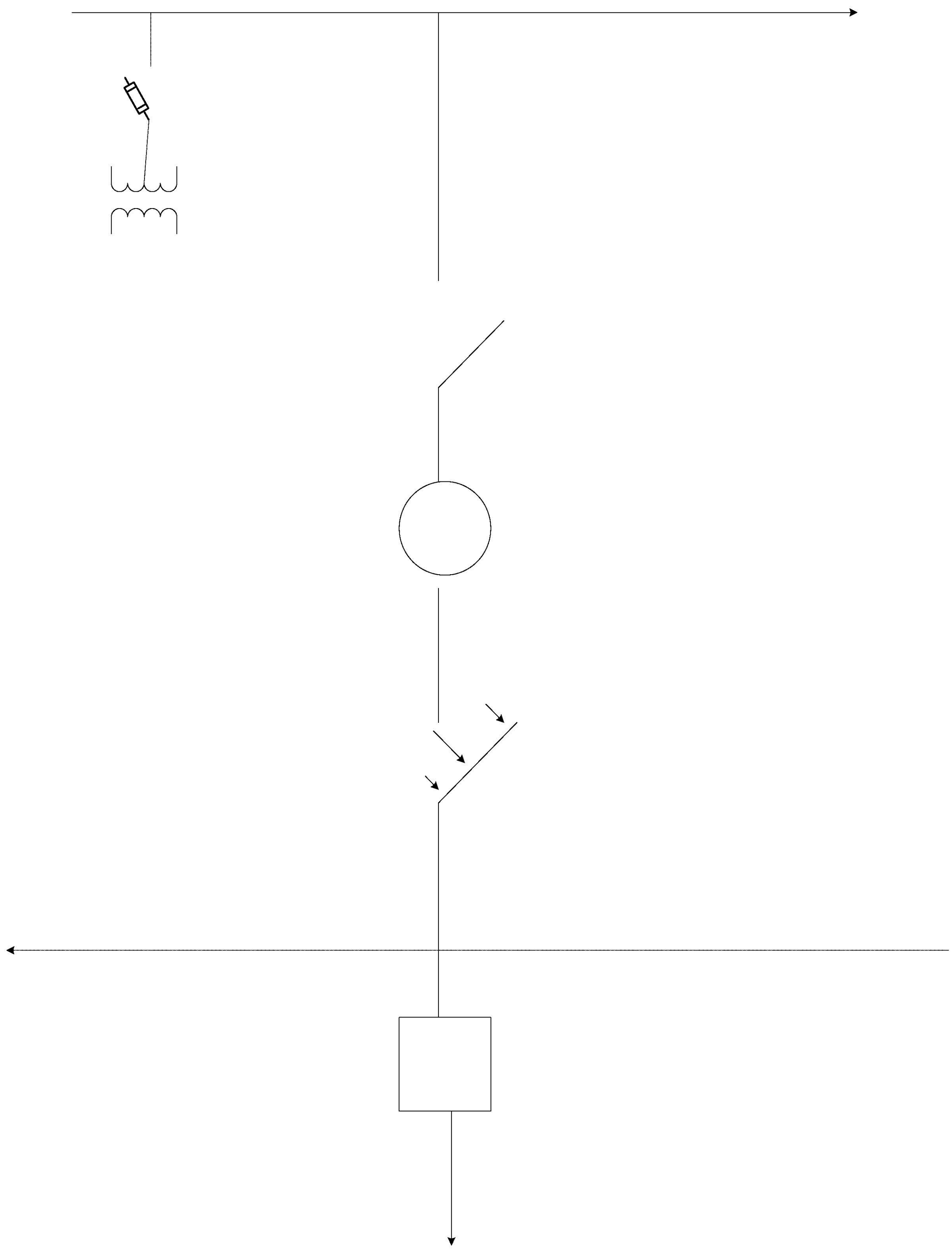
Equipment Lead Times

Typical Expected Range

- Step-Up Transformer (developer-owned, not in PacifiCorp stock, 1MVA and above) – 10 to 12 months
- Relays – 8 to 12 weeks
- Meter – 8 to 12 weeks
- Padmounted Metering Enclosure – 8 to 12 weeks
- Communication circuit – 2 months
- Recloser – 8 to 12 weeks
- Breaker – 14 to 52 weeks (1 year)
- Gang-Operated Switch – 10 to 12 weeks
- Voltage Regulator – 12 to 15 weeks
- Capacitor (substation) – 35 weeks
- RTU – 8 to 12 weeks
- Power System Stabilizer – 26 weeks (6 months)

Lead times are subject to change due to industry and market conditions of raw materials.

Generator Interconnection One-Line for Dedicated 34.5 kV Wind-Collector Feeders with Recloser or Breaker Protection



Single p

In addition to the requirements of the main document, this appendix contains additional requirements specific to PacifiCorp-owned Wind Collector Feeders (34.5 kV).

FAULT CLEARING REQUIREMENTS

All interconnections located less than six conductor miles from the originating PacifiCorp substation shall be protected with either a fuse, or a recloser (or breaker) with instantaneous tripping enabled. Faults located in this region must be cleared quickly to minimize the impact to PacifiCorp's system. For the available fault-current levels at the six-mile point on the feeder, the customer's fuse or recloser must clear the fault in a maximum clearing time of five cycles. If the customer's fuse cannot meet this requirement, the customer must install a recloser with protective relays to meet the five-cycle maximum clearing time requirement.

Interconnections located past the six-mile point on the feeder will be allowed to have fuses or re-closers that clear faults within 15 cycles at the available fault current level at the tail-end of the customer's collector system.

PacifiCorp reserves the right to modify the future configuration of these collector feeders. Future re-configurations which result in an interconnection being located within six conductor miles of the originating substation will require the customer to meet the fault-clearing requirements listed above.

Customers that have a recloser as their fault-clearing device must, upon request from PacifiCorp, provide fault records in a timely manner. If these fault records are required to troubleshoot an operating problem, these records will be needed within 48 hours of being requested.

AUTOMATIC RECLOSING

PacifiCorp's substation feeder breaker will be set to issue one automatic reclose approximately 15 to 30 seconds after it opens. The customer's equipment must be designed to handle this automatic reclose without incurring damage to the wind generators.

Exhibit PAC/501
Ortega/150

UPS CampusShip: View/Print Label

1. **Print the label(s):** Select the Print button on the print dialog box that appears. Note: If your browser does not support this function select Print from the File menu to print the label.

2. **Fold the printed label at the dotted line.** Place the label in a UPS Shipping Pouch. If you do not have a pouch, affix the folded label using clear plastic shipping tape over the entire label.

3. **GETTING YOUR SHIPMENT TO UPS**
   Customers without a Daily Pickup
   - Schedule a same day or future day Pickup to have a UPS driver pickup all your CampusShip packages.
   - Hand the package to any UPS driver in your area.
   - Take your package to any location of The UPS Store®, UPS Drop Box, UPS Customer Center, UPS Alliances (Office Depot® or Staples®) or Authorized Shipping Outlet near you. Items sent via UPS Return Services℠ (including via Ground) are accepted at Drop Boxes.
   - To find the location nearest you, please visit the Resources area of CampusShip and select UPS Locations.

   Customers with a Daily Pickup
   - Your driver will pickup your shipment(s) as usual.

FOLD HERE

PACIFICORP TRANSMISSION
5038135740
PACIFICORP
825 NE MULTNOMAH SUITE 1600
PORTLAND OR 97232

LTR 1 OF 1

SHIP TO:
RICHARD FREE
THREEMILE CANYON WIND I, LLC
6400 N.W. 86TH STREET
C/O JOHN DEERE CREDIT - WIND ENERGY
JOHNSTON IA 50131-3087

IA 503 9-21

UPS NEXT DAY AIR 1

TRACKING #: 1Z 948 574 01 9114 9938

BILLING: P/P

PacifiCorp Accounting: 12580
Contents / Sender: WS Fully EXE GIA

CS 10.5.18. WXPIE60 78.0A 04/2008

TM

Copy for File
Original sent to John Lee

LIMITED GUARANTY

Limited Guaranty, dated as of July 11, 2008, by Deere & Company, a Delaware corporation ("Guarantor"), in favor of PacifiCorp, an Oregon corporation ("Company").

For value received, Guarantor hereby absolutely and unconditionally guarantees the prompt and complete payment when due, whether by acceleration or otherwise, of all obligations and liabilities, up to a maximum of $1,700,000, whether now in existence or hereafter arising, of Threemile Canyon Wind I, LLC, an Oregon limited liability company ("Threemile"), to Company pursuant to the terms of the Distribution Generator Interconnection Agreement ("DGIA") entered into between Threemile and Company on or about July 11, 2008 (the "Obligations"). This Guaranty is one of payment and not of collection and shall apply regardless of whether recovery of all such Obligations may be or become barred by any statute of limitations, discharged, or uncollectible in any bankruptcy, insolvency or other proceeding, or otherwise unenforceable. Notwithstanding anything to the contrary herein, Guarantor's obligation to Company includes reasonable costs and expenses incurred by Company in enforcing this Guaranty, or in enforcing any of the Obligations against Threemile.

All sums payable by Guarantor hereunder shall be made in freely transferable and immediately available funds without any setoff, deduction or withholding unless such setoff, deduction or withholding is required by applicable law. If Guarantor is so required to setoff, deduct or withhold, then Guarantor shall pay, in addition to the payment to which Company is otherwise entitled, such additional amount as is necessary to ensure that the net amount actually received by Company (free and clear of any setoff, deduction or withholding) will equal the full amount which Company would have received had no such setoff, deduction or withholding been required.

Guarantor hereby waives notice of acceptance of this Guaranty and notice of the Obligations and any action taken with regard thereto, and waives presentment, demand for payment, protest, notice of dishonor or non-payment of the Obligations, suit, or the taking of and failing to take other action by Company against Threemile, Guarantor or others. Guarantor hereby waives any defense of Threemile or any other guarantor.

Any and all suretyship defenses are hereby waived by Guarantor. Without limitation, Company may at any time, whether before or after termination of this Guaranty, and from time to time without notice to or consent of Guarantor and without impairing or releasing the obligations of Guarantor hereunder: (1) make any change in the terms of the Obligations; (2) take or fail to take any action of any kind in respect of any security for the Obligations; (3) exercise or refrain from exercising any rights against Threemile or others in respect of the Obligations; (4) compromise or subordinate the Obligations, including any security therefor; or (5) apply any sums received to any indebtedness for which Threemile is liable, whether or not such indebtedness is an Obligation.

It is understood and agreed that this Guaranty shall continue in full force and effect with respect to all Obligations arising prior to its termination. This Guaranty shall automatically terminate and be of no further force or effect on the date that Threemile has tendered final payment for all actual design, engineering, construction and procurement costs associated with the interconnection facilities and upgrades contemplated by the DGIA.

Guarantor further agrees that this Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time payment, or any part thereof, of any Obligation is rescinded or must otherwise be restored or returned due to bankruptcy or insolvency laws or otherwise.

Until all Obligations are indefeasibly paid, Guarantor hereby waives all rights of subrogation, reimbursement, contribution, and indemnity from Threemile and any collateral held therefor, and Guarantor hereby subordinates all rights under any debts owing from Threemile to Guarantor, whether now existing or hereafter arising, to the prior payment of the Obligations. No payment in respect of any such subordinated debts shall be received by Guarantor. Upon any Obligation becoming due, Threemile or its assignee, trustee in bankruptcy, receiver, or any other person having custody or control over any or all of Threemile's property is authorized and directed to pay to Company the entire unpaid balance of the debt before making any payments to Guarantor, and for that purpose. Any amounts received by Guarantor in violation of the foregoing shall be received as trustee for the benefit of Company and shall forthwith be paid over to Company.

Guarantor agrees that one or more successive or concurrent actions may be brought hereon against Guarantor, in the same action in which Threemile may be sued or in separate actions.

Whether or not legal action is instituted, Guarantor agrees to reimburse Company on demand for all reasonable attorneys' fees and all other reasonable costs and expenses incurred by Company in enforcing this Guaranty, or in enforcing any of the Obligations against Threemile.

Guarantor may not assign its rights nor delegate its obligations under this Guaranty in whole or part, without written consent of Company, and any purported assignment or delegation absent such consent is void, except for an assignment and delegation of all of Guarantor's rights and obligations hereunder in whatever form Guarantor determines may be appropriate to a partnership, corporation, trust, or other organization in whatever form that succeeds to all or substantially all of Guarantor's assets and business and that assumes such obligations by contract, operation of law, or otherwise. Upon any such delegation and assumption of obligations, and, if required, the written consent of Company, which consent shall not be unreasonably withheld, Guarantor shall be relieved of and fully discharged from all obligations hereunder, whether such obligations arose before or after such delegation and assumption.

The failure of Company to enforce any of the provisions of this Guaranty at any time or for any period of time shall not be construed to be a waiver of any such provision or the right thereafter to enforce the same. All remedies of Company shall be cumulative. The terms and provisions hereof may not be waived, altered, modified, or amended except in a writing executed by Guarantor and a duly authorized officer of Company.

This Guaranty is the entire and only agreement between Guarantor and Company with respect to the guaranty of the Obligations of Threemile by Guarantor. All representations, warranties, agreements, or undertakings heretofore or contemporaneously made, which are not set forth herein, are superseded hereby.

Any demand for payment, notice, request, instruction, correspondence or other document to be given hereunder by any party to another shall be in writing and delivered personally, mailed by certified mail(postage prepaid and return receipt requested), by facsimile or via overnight express mail service, as follows:

If to Creditor:

PacifiCorp
825 NE Multnomah St., Suite 1800
Portland, OR 97232
Attn: Credit Manager
Fax: 503-813-5609

If to Guarantor:

Deere & Company
One John Deere Place
Moline, IL 61265-8098
Attn: Treasurer

With a copy to:

John Deere Renewables, LLC
6400 86th Street
Johnston, IA 50131
Attn: Manager, Wind Energy Administration

This Guaranty shall be governed by and construed in accordance with the internal laws of the state of Oregon without giving effect to principles of conflict of law. Guarantor and Company jointly and severally agree to the exclusive jurisdiction of courts located in the state of Oregon over any disputes arising or relating to this Guaranty.

DEERE AND COMPANY

By Martin L. Wilkinson
Martin L. Wilkinson, Vice President