BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism	)))))	UE 296 FINAL SCHEDULE OF EXHIBITS OF NOBLE AMERICAS ENERGY SOLUTIONS LLC

Noble Americas Energy Solutions LLC ("Noble Solutions") hereby submits its Final Schedule of Exhibits in this proceeding before the Public Utility Commission of Oregon. To ensure the record is complete Noble Solutions is providing final copies of the numbered exhibits offered at the hearing. The following exhibits were admitted at the hearing: Noble Solutions/200, Noble Solutions/203, Noble Solutions/204, Noble Solutions/205, Noble Solutions/206, and Noble Solutions/207. The following exhibits were offered but not admitted at the hearing: Noble Solutions/201 and Noble Solutions/202.

RESPECTFULLY SUBMITTED on August 28, 2015.

RICHARDSON ADAMS, PLLC

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UE 296 – Noble Solutions' Hearing Exhibits

(1) Exhibit: Noble Solutions/200
Description: PacifiCorp's Response to Noble Solutions' Data Request 5.27
Status: **Admitted**

(2) Exhibit: Noble Solutions/201
Description: OPUC Order No. 10-210
Status: **Offered but Excluded**

(3) Exhibit: Noble Solutions/202
Description: OPUC Order No. 11-512
Status: **Offered but Excluded**

(4) Exhibit: Noble Solutions/203
Description: PacifiCorp's Response to Noble Solutions' Data Request 5.29
Status: **Admitted**

(5) Exhibit: Noble Solutions/204
Description: PacifiCorp's Response to Noble Solutions' Data Requests 5.31, 5.32, 5.33, 5.34, and 5.35
Status: **Admitted**

(6) Exhibit: Noble Solutions/205
Description: PacifiCorp's Response to Noble Solutions' Data Requests 5.36 and 5.37
Status: **Admitted**

(7) Exhibit: Noble Solutions/206
Description: PacifiCorp's Response to Noble Solutions' Data Request 5.39
Status: **Admitted**

(8) Exhibit: Noble Solutions/207
Description: PacifiCorp's Response to Noble Solutions' Data Request 5.41 and attachments
Status: **Admitted**

Exhibit: Noble Solutions/200

Description: PacifiCorp's Response to Noble Solutions' Data Request 5.27

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Reference PAC/500, Dickman/84:5-8. Please identify all instances in the past ten years in which sales of RECs have been recognized in the "property sales balancing account" and credited to Oregon customers, as alleged by Mr. Dickman. In each instance, please identify:

(a) The Oregon docket number in which the credit was recognized;

(b) The amount of the credit (total dollars);

(c) The amount of the credit expressed on a $-per-REC sold basis (where 1 REC is equivalent to 1 MWh);

(d) The basis for allocating Oregon's share of the revenues from the REC sales (e.g., Situs, SE, SG, other);

(e) The basis for allocating Oregon's share of the revenues from the REC sales among customer classes;

(f) The basis for allocating Oregon's share of the revenues from the REC sales between direct access customers and cost-of-service customers;

(g) The amount of the average credit reflected in retail rates expressed on a $ per MWh of retail load basis for both direct access and cost-of-service customers;

(h) The work papers used to calculate the credit to direct access and cost-of-service customers for each of the dockets identified in part (a) and for each of the calculations shown in parts (b) through (g);

(i) Please identify the OPUC Order or OPUC-approved tariff explaining the treatment identified in parts (b) through (g).

Response to NAES Data Request 5.27

As explained in detail below, sales of Oregon's share of Oregon renewable portfolio standards (RPS) ineligible renewable energy credits (RECs) are recorded in the Company's property sales balancing account. Schedule 96 is periodically used to amortize amounts in the property sales balancing account. Schedule 96 was set to zero in April of 2013. The Company continues to record sales of Oregon RPS ineligible RECs in the property sales balancing account.

(a) Per Docket No. UP 260, Order No. 10-210, the Company has been recording Oregon's share of Oregon RPS ineligible RECs in the property sales balancing account since 2010. The REC sales from 2008 and 2009 were included in the

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revenue requirement in the general rate case (GRC) under Docket No. UE 217. REC sales are included in the Company's annual Property Sales Balancing Account report in Docket No. RE 71.

(b) Please refer to the annual reports filed with the Public Utility Commission of Oregon (OPUC) under Docket No. RE 71 for the credit amounts recorded in the property sales balancing account.

(c) Please refer to the response to subpart (b) above for the revenue associated with the REC sales included in the property sales balancing account. The Company will supplement this response with the number of RECs.

(d) Oregon's share of REC revenue is determined based on the System Generation (SG) factor, including a reallocation of REC revenue initially allocated system wide to reflect banking of RECs in some states in compliance with state renewable portfolio standards.

(e) The revenues from REC sales were recorded in the property sales balancing account. The property sales balancing account is amortized through Schedule 96, Property Sales Balancing Account Adjustment. Schedule 96 is designed on an equal cents per kilowatt-hour (¢/kWh) basis and is applicable to all customers, including direct access customers.

(f) Please refer to the Company's response to subpart (e) above.

(g) Please refer to Attachment NAES 5.27 -1, which provides a copy of Schedule 96, Property Sales Balancing Account Adjustment which became effective January 1, 2011, through Advice No. 10-020. The tariff rate was a credit of 0.027 ¢/kWh, for all kWh. This rate was set to amortize the balance, which included REC revenue recorded in 2010. The rate remained in place and continued to amortize additions to the balancing account until April 24, 2013, when it was set to zero in Advice No. 13-008 due to the full amortization of the balancing account at that time.

(b) Please refer to Attachment NAES 5.27 -2 which provides the rate calculation work papers for the Schedule 96 rate which became effective January 1, 2011.

(i) In Docket No. UP 260, Order No. 10-210 states that the Company will record all net proceeds of REC sales in its Property Sales Balancing Account for calendar year 2010 and beyond. This was an approval to sell RECs from resources included in Oregon rates and allocated to Oregon that are not eligible for Oregon RPS compliance. Previously sold non-eligible RPS RECs in 2008 and 2009 were handled in GRC Docket No. UE 217. In that stipulation the Company agreed to a $2.5 million revenue credit for the non-RPS eligible RECs previously sold.

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Furthermore, the Industrial Customers of Northwest Utilities (ICNU) and the Company agreed to file a request to sell Oregon RPS eligible RECs that were not currently used to meet RPS standards rather than banking them for the future. The Company agreed to file the request in Docket No. UP 266 but did not support the matter. Order No. 11-512 denied the Company the ability to sell RPS eligible RECs banked for future use. In that order, the Company stated that the risks of selling RPS-eligible RECs are likely to outweigh the benefits. The OPUC acknowledged this stating that no competent evidence contradicted that assertion.

Pacific Power Advice No. 10-020 and Advice No. 13-008 addressed changes to the rate in Schedule 96, Property Sales Balancing Account Adjustment, which amortizes revenues from the balancing account.

Exhibit: Noble Solutions/201

Description: OPUC Order No. 10-210

ORDER NO. 10-210
ENTERED 06/09/10

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UP 260

In the Matter of PACIFICORP, dba PACIFIC POWER Application Requesting Approval of Sale of Renewable Energy Credits.	ORDER

DISPOSITION: APPLICATION APPROVED WITH CONDITIONS

On April 8, 2010, the Public Utility Commission of Oregon (Commission) received an application from PacifiCorp, dba Pacific Power (Pacific Power or Company), requesting approval of the sale of Renewable Energy Credits (RECs) that are not eligible to meet Oregon Renewable Portfolio Standards (RPS), and provide an accounting order allowing the Company to record all net proceeds from the sale of RECs in a Property Sales Balancing Account for return to customers. The application is filed pursuant to ORS 757.480 and OAR 860-027-0025, and Orders No. 07-083 and No. 10-022. A description of the filing and its procedural history is contained in the Staff Report, attached as Appendix A, and incorporated by reference.

OPINION

Under ORS 757.480, a public utility doing business in Oregon shall first obtain Commission approval for any transaction to sell, lease, assign, or otherwise dispose of property. Based on a review of the application and the Commission's records, the Commission finds that the application satisfies applicable statutes and administrative rules.

At its Public Meeting on June 8, 2010, the Commission adopted Staff's recommendation to approve the requested sale of the Renewable Energy Credits and the issuance of an accounting order, subject to the conditions stated in the Staff Report attached as Appendix A.

ORDER

IT IS ORDERED that the application of PacifiCorp, dba Pacific Power, is approved, and an accounting order issued, subject to the following conditions:

1. Pacific Power will provide the Commission access to all books of account, as well as all documents, data, and records that pertain to the sale of Renewable Energy Credits.

2. Pacific Power will notify the Commission in advance of any substantive changes to the sale and transfer of Renewable Energy Credits, including any material changes in price or quantities that exceed expectations noted in the original application. Pacific Power will obtain approval from the Commission before selling any Renewable Energy Credits eligible to meet the Oregon Renewable Portfolio Standards as described in ORS §469A.025 and §469A.135.

3. Pacific Power will record all net proceeds of Renewable Energy Credit sales in its Property Sale Balancing Account and will report final gain calculations for all transactions with supporting documentation in its annual Property Sales Balancing Account Report for Commission review.

4. The Commission reserves the right to review all financial aspects of this transaction in any rate proceeding or alternative form of regulation.

Made, entered, and effective JUN 09 2010.

BY THE COMMISSION:

Becky L. Beier

Becky L. Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ITEM NO. CA7

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 8, 2010**

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** N/A

DATE: May 21, 2010

TO: Public Utility Commission

FROM: Juliet Johnson

THROUGH: Bryan Conway, Marc Hellman, and Michael Dougherty

SUBJECT: PACIFICORP: (Docket No. UP 260) Application for 1) authorization to sell Renewable Energy Credits that are not eligible to meet Oregon Renewable Portfolio Standards; and 2) an accounting order allowing for the recording of all proceeds from Renewable Energy Credit sales in PacifiCorp's Property Sales Balancing Account.

STAFF RECOMMENDATION:

Staff recommends that the Commission approve an application submitted by PacifiCorp, d.b.a. Pacific Power (Pacific Power or Company) to sell Renewable Energy Credits (RECs) that are not eligible to meet Oregon Renewable Portfolio Standards (RPS) and provide an accounting order allowing the Company to record all net proceeds from the sale of RECs in a Property Sales Balancing Account for return to customers, subject to the following conditions:

1. PacifiCorp will provide the Commission access to all books of account, as well as documents, data, and records that pertain to the sale of RECs.

2. PacifiCorp will notify the Commission in advance of any substantive changes to the sale and transfer of RECs or any material changes in price or quantities that exceed expectations noted in the original application. PacifiCorp will obtain approval from the Commission before selling any RECs eligible to meet the Oregon RPS as described in ORS §469A.025 and §469A.135.

3. PacifiCorp will record all net proceeds of REC sales in its Property Sale Balancing Account and will report final gain calculations for all transactions with supporting documentation in its annual Property Sales Balancing Account Report for Commission review.

4. The Commission reserves the right to review all financial aspects of this transaction in any rate proceeding or alternative form of regulation.

DISCUSSION:

PacifiCorp filed this application on April 8, 2010, pursuant to ORS 757.480(1)(a), OAR 860-027-0025, and Order No. 07-083 and 10-022.

Background:
RECs represent the beneficial environmental attributes of one megawatt-hour (MWh) of electricity generated from a specific renewable resource. The market demand for RECs is increasing due to new customers entering the market, corporate commitments, and regulations such as RPS.

RPS require that utilities ensure a percentage of electricity sold to their retail customers be derived from eligible renewable energy resources either through utility owned-resources generation or through the purchase of qualifying RECs.

As part of the Oregon Renewable Energy Act of 2007 (SB 838-C), the state of Oregon established its RPS for electric utilities and electricity service suppliers, now codified in ORS Chapter 469A. Eligible renewable resources include electricity generated from solar, wind, hydropower, ocean thermal, wave, tidal power, geothermal, hydrogen derived from renewable sources, and biomass, including biogas. To satisfy the Oregon RPS, these resources must be located within Western Electricity Coordinating Council territory or be designated environmentally preferable by the Bonneville Power Administration (See ORS § 469A.135).

Different states and different renewable energy incentive programs have varying eligibility requirements for RECs. The market varies depending on location, resource type, and vintage. Therefore, RECs that don't satisfy Oregon's RPS criteria may satisfy requirements of other states or programs.

Analysis:
In this application, PacifiCorp is seeking Commission approval to sell RECs that are not eligible to meet Oregon RPS. PacifiCorp's current policy is to hold all Oregon-allocated RECs that are eligible under the Oregon RPS for current and future-year Oregon RPS program compliance. Based on this practice, the Company estimates it has sufficient RECs allocated to Oregon to meet Oregon RPS requirements for years 2011 through 2016, as summarized in PacifiCorp's RPS Implementation Plan, UM 1467.

Pursuant to the direction provided in Order No. 10-022, the Company requests Commission's approval to sell RECs from resources included in Oregon rates and allocated to Oregon that are generated in calendar year 2010 and beyond that are *not* eligible for Oregon RPS compliance.

Consistent with Order No. 07-083, the Company proposes to book the Oregon-allocated gain from REC sales, net of transaction costs, to its Property Sales Balancing Account for refund to Oregon customers with interest accrual from the date of revenue receipt, utilizing the Commission-approved rate of return until amortization begins. The Company will report in its annual Property Sales Balancing Account report any REC sales that occurred during the applicable reporting period, for review by the Commission.

Staff believes these transactions benefit PacifiCorp's Oregon customers in that gains are returned to Oregon customers and transactions do not adversely impact PacifiCorp's ability to meet Oregon RPS.

Although this application refers to RECs that are generated in calendar year 2010 and beyond that are *not* eligible for Oregon RPS compliance, the Company has previously sold approximately $2.5 million non-eligible RPS RECs in 2008 and 2009. The issue of the 2008 ($1 million) and 2009 ($1.5 million) gains are being examined in PacifiCorp's current General Rate Case, Docket No. UE 217.

PROPOSED COMMISSION MOTION:

PacifiCorp's application be approved and an accounting order issued subject to the five recommended conditions.

PMM UP260

Exhibit: Noble Solutions/202

Description: OPUC Order No. 11-512

ORDER NO. 11 512

ENTERED DEC 20 2011

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UP 266

In the Matter of PACIFICORP, dba PACIFIC POWER, Application for Policy Determination for Sale of Renewable Energy Credits.	ORDER

DISPOSITION: APPLICATION DENIED

I. INTRODUCTION

In this order, we address PacifiCorp dba Pacific Power's application relating to the sale of certain renewable energy credits (RECs). Because the application fails to meet the applicable legal standards, we deny Pacific Power's application.

II. PROCEDURAL HISTORY

Pacific Power filed its application in this docket on August 26, 2010. A number of parties intervened in the docket, including the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), the Oregon Department of Energy (ODOE), the Renewable Northwest Project (RNP), Idaho Power Company, and Portland General Electric Company.[1] These parties, along with the Staff of the Public Utility Commission of Oregon, filed a series of comments. All parties waived the right to file testimony or evidence, waived a hearing on the disputed issues, and waived briefing.

III. BACKGROUND

This application is somewhat unusual, in that sense that ICNU—rather than Pacific Power—is the party that wants Pacific Power to sell the RECs at issue in Pacific Power's application.

[1] PGE and Idaho Power intervened in this docket but did not actively participate in the proceedings.

By way of background, Pacific Power has been authorized since 2010 to sell certain RECs that are *not eligible* for Oregon renewable portfolio standard (RPS) compliance.[2] The company has banked all Oregon-allocated, RPS-*eligible* RECs for future RPS compliance, however, since the time the Oregon RPS was adopted.

The company banks RPS-eligible RECs to ensure it will be able to meet future RPS targets in a cost-effective manner. By banking the RECs, the company limits its exposure to potentially volatile future market costs. The company's policy of banking RPS-eligible RECs is reflected in the company's RPS implementation plan, which was acknowledged by the Commission in Order No. 10-172 (May 4, 2010).[3]

ICNU believes that Pacific Power and its customers would benefit from a change to this policy. ICNU wants Pacific Power to immediately begin selling Oregon RPS-eligible RECs. Obviously, ICNU does not ordinarily control a utility's decision to file an application for the sale of utility property, but this issue was apparently addressed during negotiations during Pacific Power's last general rate revision proceeding, docket UE 217. As part of those negotiations, Pacific Power agreed to file the instant application.

Although Pacific Power agreed to file the application, and did so, the company makes clear that it does not agree with ICNU's position. To the contrary, the company believes the risks of selling RPS-eligible RECs currently outweigh the potential benefits and prefers to maintain its current policy. Consequently, Pacific Power incorporates into its application a number of conditions, including the condition that the Commission hold it harmless for any financial losses resulting from any such REC sales. Pacific Power asks the Commission to address this issue.

IV. DISCUSSION

We have noted the unusual posture of this docket. Pacific Power, the applicant, argues that its own application cannot meet the statutory "no harm" standard. ICNU, as an intervenor, argues that sale of Oregon RPS-eligible RECs *can* meet the statutory standard, and that the Commission should, in fact, order Pacific Power to make such sales. We note this unusual posture because the positions of the parties otherwise appear somewhat confusing.

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[2] *See In re PacifiCorp Application Requesting Approval of Sale of Renewable Energy Credits*, Docket UP 260, Order No. 10-210 (Jun 9, 2010).
[3] The company's current RPS-compliance position with respect to banked RECs is deemed confidential and is subject to the terms of the protective order in this docket. (Order No. 10-339).

A. Positions of the Parties

1. Pacific Power

Pacific Power believes that selling Oregon RPS-eligible RECs at this time is risky, because the REC market is volatile and unpredictable.[4] The market has limited depth with little or no price transparency. Moreover, Pacific Power asserts, the market is mostly opportunistic, with buyers engaged in transactions only a few times a year. The transactions take time and effort to structure, ultimately requiring approximately nine months to complete. In other words, the company explains, the market is risky, volatile, lacks market depth, and offers only limited and burdensome opportunities to make sales.

Given Pacific Power's assessment of the risks involved, the company would consider selling RPS-eligible RECs only if the Commission imposes certain conditions. These key conditions are part of the company's application: First, Pacific Power states, the Commission should set a confidential price floor for REC sales, to limit potential exposure to losses. The company suggests a number of somewhat complex methods the Commission could use to calculate such a floor. Second, the Commission should limit the number of sales to no greater than 75 percent of the company's forecast generation in a calendar year. Finally, the Commission should hold the company harmless if, in the future, it must purchase more expensive RECs to comply with its RPS obligations. If these conditions are met, the company states in its opening comments, it would *consider* selling Oregon RPS-eligible RECs.

Pacific Power emphasizes that selling RPS-eligible RECs is not, in its view, the prudent course of action. The company currently carries RPS-eligible RECs forward indefinitely for purposes of RPS compliance. By helping to ensure that RPS targets will be met, the company argues, its current policy "provides protection for customers against the risks associated with the potentially volatile costs of future RPS compliance" in the future.[5] The company estimates that it will have sufficient RECs allocated to Oregon to meet RPS requirements for a number of years.

Because the company believes that the long-term risks of selling RPS-eligible RECs outweigh the short-term benefits, it is "unwilling to take on the future RPS compliance risk of such an action without some form of cost recovery protection."[6]

2. ICNU

ICNU is the only party that affirmatively advocates the sale of Pacific Power's Oregon RPS-eligible RECs. ICNU argues that the Commission should require the company to sell

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[4] The company asserts that volatility is affected by, among other things, changes in state RPS policy developments, voluntary program developments in various western states, and the looming potential of future carbon legislation.
[5] Pacific Power's Application at 7.
[6] Pacific Power's Reply Comments at 7.

RECs, and the company should also bear responsibility for any increase in future RPS-compliance costs created by such sales.

ICNU believes that the sale of RPS-eligible RECs, particularly in the near-term, may greatly benefit customers.[7] According to ICNU, Pacific Power has enough renewable resources to meet RPS requirements for a long period of time.[8] At the same time, the REC market has the potential to generate large benefits that should be shared with customers. ICNU believes that RPS-eligible RECs should not sit uselessly in "banks" where they earn no interest or revenue for customers. Rather, ICNU argues, Pacific Power should be required to sell RECs quickly and return the benefits to customers. ICNU argues that this would help off-set the costs of Pacific Power's recent rate increases.

ICNU agrees with Pacific Power that the REC market is new and highly volatile, but believes that time-sensitive opportunities exist for utilities to reap significant rewards, particularly with REC sales to California.

ICNU disagrees with the manner in which Pacific Power proposes to sell RECs in its application, however. Pacific Power describes a burdensome process that would take approximately nine months to consummate, that consists of seeking out new REC sales contracts composed entirely of bundled Oregon RECs. ICNU argues that this approach of selling bundled RECs is unnecessarily cumbersome. Moreover, because this method of making REC sales takes so much time, and ICNU wants Pacific Power to sell RECs immediately, it would, in ICNU's view, render the company's application of little value.[9]

Instead, ICNU argues, the company should begin selling RECs immediately and share the revenues from existing REC contracts with Oregon customers. ICNU argues that customers have paid their full share of the cost of acquiring the company's various renewable resources, so they are entitled to such revenues.

Finally, ICNU rejects the conditions under which Pacific Power states that it would consider selling RPS-eligible RECs. ICNU argues that the company's proposal for a "confidential floor" for RPS-eligible REC sales might simply drive down REC prices by setting an artificially low price point for sales. Moreover, while the company has offered several methods for calculating such a floor, none is adequately supported. If a floor is set, ICNU argues, any REC sales should be expected to significantly exceed that floor, and all sales should be subject to the Commission's "traditional prudence and reasonableness

[7] ICNU wants Pacific Power to sell 2011, Oregon-allocated, RPS-eligible RECs immediately. Despite its focus on 2011 RECs, ICNU believes that a Commission decision in this docket would also provide guidance for Pacific Power and PGE with respect to future opportunities for REC sales that might benefit Oregon customers.

[8] ICNU disputes Pacific Power's assertions about the status of the company's RPS compliance position, finding them to be overly conservative for various reasons. The company's estimates have been designated confidential, so we do not discuss them here other than to note the existence of the controversy.

[9] ICNU also argues that Oregon customers should receive an allocated share of benefits from 2011 RECs that are sold under both existing and new REC sales contracts.

standard." Finally, ICNU states that the Commission lacks legal authority to hold the company harmless for any losses from REC sales.

3. *CUB*

CUB believes that Pacific Power should continue to bank Oregon RPS-eligible RECs. CUB argues that an application to sell utility property must meet a no-harm standard. Because the application asserts that the risk of selling RPS-eligible RECs outweighs the benefits, it must be denied.

With respect to ICNU's position that the Commission should order Pacific Power to sell RPS-eligible RECs, CUB argues that the Commission lacks authority to *require* Pacific Power to sell RECs. Nor, CUB argues, can the Commission legally hold a utility harmless for financial losses created by REC sales. If a utility is positioned to make profitable sales of RPS-eligible RECs and wishes to engage in such sales, CUB asserts, the utility must assume responsibility for the downside risk of such trading.[10]

Finally, CUB argues, the application should be denied because it undermines ORS 469A.075(1).[11] That statute requires Oregon utilities to submit RPS compliance plans with the Commission every two years to ensure that RPS requirements are met in a least-cost, least-risk manner. CUB argues that it is illogical for a utility to build resources in a least-cost, least-risk manner, only to sell the RECs generated by the resources and face exposure to the volatile REC market in future years. If a utility wants to sell RPS-eligible RECs, CUB argues, the utility's RPS compliance plan should first reflect that plan, and the company should be held responsible for its decisions.

4. *ODOE*

ODOE agrees that Pacific Power's application fails to meet the no-harm standard, and must therefore be denied. ODOE also agrees with CUB that a plan to sell RPS-eligible RECs should be evaluated in the broader context of an RPS implementation plan (or an Integrated Resource Plan (IRP)) before implementation. In any such proceedings, a utility's plan to sell RPS-eligible RECs should be subject to a risk-benefit analysis, and any potential sale must ultimately be prudent in light of Oregon's RPS requirements.

5. *RNP*

Like CUB and ODOE, RNP argues that Pacific Power's application fails to meet the no-harm standard and should therefore be denied. RNP argues that Pacific Power's application does not even attempt to show that existing market conditions or low future

[10] CUB notes that the prudent costs of RPS compliance are obviously recoverable under Oregon law, but argues that the losses incurred as a result of imprudent market trading are not a justifiable, prudent, or necessary expense for meeting RPS requirements.
[11] *See also* OAR 860-083-0050.

RPS compliance costs justify selling RECs, rather than banking them. To the contrary, the application concedes that the REC market is "volatile and unpredictable," and that such sales are potentially harmful.

RNP also questions the logic of modifying a utility's internal business policy against the utility's judgment.[12] It argues that a utility's REC-sales strategy is unlikely to be successful unless that strategy is developed by and actively managed by the utility. Here, Pacific Power expresses no desire to change its existing policies.[13]

Similarly, RNP argues, incentives for appropriate management of REC sales should include the risk of non-recovery for poorly reasoned decisions. If Pacific Power does sell RPS-eligible RECs, it must retain the same risk of non-recovery that applies to all of its business decisions (unless the Commission orders the company to sell RECs).

Finally, RNP agrees with other intervenors that any significant shift in near-term strategy for RPS compliance should first be addressed in a utility's RPS implementation plan. Under the conditions present here, however, RNP believes the application must be denied.

6. Commission Staff

Staff agrees that Pacific Power's application should be rejected as filed. Staff also rejects the conditions proposed by ICNU.[14] Staff emphasizes that a key goal is to ensure that Pacific Power prudently maintains its balance of RPS-eligible RECs to meet current and future RPS requirements, and believes that Pacific Power's current policy of banking RPS-eligible RECs meets that objective.

Staff opines, however, that there may be conditions under which a utility may benefit from arbitrage through buying and selling of RPS-eligible RECs while effectively managing the associated risk. While Staff does not appear to be asking the Commission to *impose* those conditions on Pacific Power or force the company to sell RPS-eligible RECs, it does offer a framework for the company's consideration.

We will not detail each of Staff's proposed conditions here,[15] but under Staff's general framework, the Commission could allow Pacific Power to buy and sell Oregon RPS-eligible RECs without Commission pre-approval, so long as there was no net change in the number of RECs the company owned at the end of the calendar year.

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[12] RNP believes that, in general, retaining RECs to achieve future RPS compliance effectively hedges risk and keeps costs low for customers over the long term.

[13] RNP also points out that the company's application would involve the cumbersome application of a "market floor," which, even if litigated to a conclusion, could quickly become outdated, as well as a hold-harmless standard that removes all incentives for the company to manage risk.

[14] Staff does not believe Pacific Power should sell Oregon-eligible RECs, outright, because it does not consider Pacific Power currently to be in a surplus REC situation.

[15] *See* Staff's Opening Comments at 3-4; Staff's Reply Comments at 3-4. Staff's comments address 2011 sales, but could serve as a framework for future years.

In addition, Pacific Power could be required to file certain reports during the year; the net sales proceeds could be placed in a balancing account (with 90 percent allocated for return to customers); and other safeguards could be imposed. Staff also suggests that the Commission could require Pacific Power to set forth in future IRP and RPS implementation plans and analysis of the most cost-effective way to achieve RPS compliance, taking into consideration of the risks of buying and selling RPS-eligible RECs.

7. *Pacific Power's Reply*

In reply comments, Pacific Power firms up its opposition to selling RPS-eligible RECs. It agrees that it cannot meet the no-harm standard with respect to RPS-eligible REC sales, and states that it is simply unwilling to make such sales at this time.[16]

Pacific Power concedes that Staff has provided a "creative proposal" that might provide a useful framework for the company to take advantage of REC sales opportunities in the future while providing some customer protections. The company states that it is willing to engage in dialogue on Staff's proposal, but does not believe the proposal would allow the company to overcome the risks of pursuing RPS-eligible REC sales at this time.

Pacific Power also asserts that because ICNU is the party actively seeking to force the company to sell RPS-eligible RECs, ICNU must make a compelling case that such sales will not harm Pacific Power's customers in the long run. Pacific Power asserts that ICNU has not made such a showing.

In short, Pacific Power asserts, it is simply "unwilling to trade what it knows today regarding Oregon's RPS program for a high degree of future uncertainty, without some type of recovery protection." Thus, unless the Commission somehow directs otherwise, the company "will continue in its current path of banking RPS-eligible RECs for future RPS compliance in Oregon."[17]

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[16] The company also agrees that it must demonstrate that such sales will not harm customers, and that any strategy for selling RPS-eligible RECs should first be vetted through a broader process, such as the RPS implementation plan process.

[17] Pacific Power's Reply Comments at 6. Pacific Power also notes that ICNU's suggestion that customers should share any benefits from existing contracts for sales of RECs is problematic, because the existing contracts were entered into with the intention that RPS-eligible Oregon RECs would be banked for future compliance. Accordingly, REC sale revenues from *existing* contracts have been committed to other states where the RECs are not required or eligible for RPS compliance, pursuant to various rate case or other adjustment mechanism settlements. It cannot "retroactively allocate revenues to Oregon from such prior sales." Pacific Power's Reply Comments at 7.

B. Commission Resolution

The Commission is tasked with addressing the relief requested in Pacific Power's application. Given the unusual posture of the parties in this docket, we observe that the application itself is somewhat unusual. Consequently, we will briefly discuss our understanding the application itself.

The company styles its application as a "request for policy determination." This is not, however, the type of docket in which the Commission ordinarily makes broad policy determinations. Nor would a "policy determine" resolve the real issue in dispute.

After review of the application and comments, we understand the application to be asking the following questions: First, will the Commission grant Pacific Power's application to sell RPS-eligible RECs, as filed, including Pacific Power's stated conditions for such sales? And, second, will the Commission order Pacific Power to make such sales under conditions recommended by other parties? The answer to both questions is no.

We will not grant the company's application as filed because it fails to meet the applicable legal standard. In any application for the sale of utility property, the applicant must meet the statutory standard established by ORS 757.480. We have previously determined that the statute creates a no-harm standard.[18]

In this case, the application is deficient for a number of reasons. Most importantly, the company concedes in the application that it believes the risk of selling RPS-eligible RECs is likely to outweigh the benefits. No competent evidence contradicts that assertion. Consequently, the application fails to meet the no-harm standard. In addition, one of the conditions in the application is that the Commission hold the company harmless for any increased future RPS compliance costs caused by such sales. This condition undermines the standard established by ORS 757.480 and our obligation to review the prudence of utility investments. Thus, we will not grant the application as filed.

Nor will we order the company to sell RPS-eligible RECs under conditions proposed by other parties. No party has pointed to any authority (and we are aware of none) that would authorize the Commission to force Pacific Power to sell company-owned RECs when the company prefers to bank them. Pacific Power has stated unequivocally that it does not intend to sell RPS-eligible RECs, and that it would only consider making such sales under the company's own stated conditions. It is simply unclear how we might force Pacific Power to adopt the conditions proposed by Staff or any other party.

In light of these considerations, we find no legal justification for granting the application to sell RECs.

[18] As RNP notes, we have at times required a utility to meet an even higher "net benefits" standard under certain circumstances. We need not decide here which standard applies here, as we find the application fails to meet even the lower no-harm standard.

If a utility wishes to sell RPS-eligible RECs in the future, we agree with various commenters that it would be preferable for a utility to first raise its intentions in the context of an IRP or RPS-implementation plan. The second step would be to file an application for the sale of utility property that meets the standards established by ORS 757.480. We also concur with Pacific Power that Staff's proposed framework is a promising starting point for structuring the sales of RPS-eligible RECs in a way that incorporates useful customer safeguards against future RPS compliance costs.

V. ORDER

IT IS ORDERED that the application of PacifiCorp, dba Pacific Power, for a Policy Determination for Sale of Renewable Energy Credits, is denied.

Made, entered, and effective DEC 20 2011.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

Exhibit: Noble Solutions/203

Description: PacifiCorp's Response to Noble Solutions' Data Request 5.29

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.29

NAES Data Request 5.29

Reference PAC/500, Dickman/84:5-8.

(a) Please identify all RPS planning documents that suggest that PacifiCorp will sell RECs freed up by direct access customers instead of banking those RECs for use of future RPS compliance. Identify the page number in the documents provided that support the assertion.

(b) Is it PacifiCorp's position, with respect to RECs that are derived from rate-based resources included in Schedule 200 and long-term power purchases in Schedule 201, that such RECs were procured primarily to meet RPS requirements or to bank and then sell in future years?

Response to NAES Data Request 5.29

(a) As stated on page five of PacifiCorp's 2014 Renewable Portfolio Standard (RPS) Compliance Report[1], at this time PacifiCorp does not plan to sell any Oregon-allocated RECs.

(b) Renewable energy credits (RECs) associated with rate-based resources and long-term power purchases are derived from the generation of renewable resources used to serve PacifiCorp load. Oregon's RPS requires that PacifiCorp serve a certain percentage of load using renewable resources. RECs can be used to comply with the RPS. PacifiCorp uses the RECs to meet RPS requirements. Currently, PacifiCorp banks the unused RECs and uses them for future compliance.

[1]https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/OR_RPS_Compliance_Report_2013.pdf

Exhibit: Noble Solutions/204

Description: PacifiCorp's Response to Noble Solutions' Data Requests 5.31, 5.32, 5.33, 5.34, and 5.35

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.31

NAES Data Request 5.31

Reference PAC/500, Dickman/83:13-15, asserting that Noble Solutions' proposal for a REC credit is "conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads." In OPUC docket UE 245 PacifiCorp argued, "Depending on the location of the lost load and the existing transmission arrangements with BPA and the Company's transmission function, there is little to no opportunity to realize the value of freed-up transmission with BPA." UE 245 PAC/300, Duvall/34-35.

(a) Does Mr. Dickman believe that the location of an Oregon customer impacts the Company's ability to recognize the value of RECs that may be freed up if a customer elects direct access?

(b) If yes, please explain why and provide all supporting evidence of the impacts of a customer's location in Oregon on the value of freed-up RECs.

(c) Does Mr. Dickman believe little opportunity exists to realize the value of freed-up RECs?

(d) If yes, please explain why and provide all supporting evidence of the REC market's illiquidity or other limitations.

Response to NAES Data Request 5.31

(a) No.

(b) Please refer to the Company's response to subpart (a) above.

(c) Yes. The Public Utility Commission of Oregon (OPUC) has indicated Oregon-allocated renewable energy credits (REC) should be banked and retained. The Company will not realize value from those RECs. Any sale of RECs must comply with the requirements for the sale of utility property established in Oregon Revised Statute (ORS) 757.480.

(d) Please refer to the Company's response to subpart (c) above.

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.32

NAES Data Request 5.32

Reference PAC/500, Dickman/83:13-15, asserting that Noble Solutions' proposal for a REC credit is "conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads." In OPUC docket UE 245, PacifiCorp argued "the Company may need to acquire additional transmission to deliver freed-up generation to market in order to realize the transition adjustment determined for the lost load." UE 245 PAC/300, Duvall/35.

(a) Does Mr. Dickman believe that the Company may need to acquire additional RECs to deliver freed-up generation to market in order to realize the transition adjustment determined for the lost direct access load?

(b) If yes, please explain why and provide all supporting evidence of the need to acquire additional RECs for this purpose.

Response to NAES Data Request 5.32

(a) No.

(b) Please refer to the Company's response to subpart (a) above.

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.33

NAES Data Request 5.33

Reference PAC/500, Dickman/83:13-15, asserting that Noble Solutions' proposal for a REC credit is "conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads." In OPUC docket UE 245, the Company argued: "Because customers that elect direct access retain the right to return to cost of service rate schedules, the Company must continue to plan for these customers and therefore must retain transmission rights to carry out this obligation." UE 245 PAC/300, Duvall/35.

(a) Does Mr. Dickman believe it would be difficult to procure RECs to serve a direct access customer that returns to cost-of-service rates at the conclusion of the one-year or three-year opt-out programs?

(b) If yes, please explain why and provide all supporting evidence of the REC market's illiquidity or other limitations on acquisition of RECs for this purpose.

(c) If a direct access customer in the one-year program for service year 2016 were to return to cost-of-service in 2017, please explain why the PacifiCorp-owned or PacifiCorp-contracted RPS resources would not generate 2017 compliance year RECs that could be used to meet RPS needs associated with that customer.

Response to NAES Data Request 5.33

(a) Not at the present time.

(b) Please refer to the Company's response to subpart (a) above.

(c) PacifiCorp-owned and PacifiCorp-contracted renewable portfolio standards (RPS) resources will generate 2017 compliance year renewable energy credits (REC) that will be used to meet the RPS needs of Oregon cost-of-service (COS) customers either in 2017 or in a future compliance year.

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.34

NAES Data Request 5.34

Reference PAC/500, Dickman/83:13-15, asserting that Noble Solutions' proposal for a REC credit is "conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads." In OPUC docket UE 245, the Company argued: "Because customers that elect direct access retain the right to return to cost of service rate schedules, the Company must continue to plan for these customers and therefore must retain transmission rights to carry out this obligation." UE 245 PAC/300, Duvall/35.

(a) Does Mr. Dickman believe that it would be difficult to procure RECs necessary to serve a customer that provided four years advance notice to return to cost-of-service rates after enrolling in the five-year opt-out program, as required by Schedule 296?

(b) If yes, please explain why and provide all supporting evidence of the REC market's illiquidity or other limitations.

Response to NAES Data Request 5.34

(a) Not at the present time.

(b) Please refer to the Company's response to subpart (a) above.

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.35

NAES Data Request 5.35

Reference PAC/500, Dickman/83:13-15, asserting that Noble Solutions' proposal for a REC credit is "conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads." In OPUC docket UE 245, the Company argued: "Because customers that elect direct access retain the right to return to cost of service rate schedules, the Company must continue to plan for these customers and therefore must retain transmission rights to carry out this obligation." UE 245 PAC/300, Duvall/35.

(a) Does Mr. Dickman believe that it would be difficult to procure RECs on the short-term market to serve a direct access customer that returned to cost-of-service rates in an emergency?

(b) If yes, please explain why and provide all supporting evidence of the REC market's illiquidity or other limitations.

Response to NAES Data Request 5.35

(a) Not at the present time.

(b) Please refer to the Company's response to subpart (a) above.

Exhibit: Noble Solutions/205

Description: PacifiCorp's Response to Noble Solutions' Data Requests 5.36 and 5.37

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.36

NAES Data Request 5.36

Reference PAC/800, Ridenour/4:14-15, testifying: "An ESS has four weeks from the first day of the open enrollment window to submit a DASR." For each enrollment window that PacifiCorp has offered direct access since enactment of S.B. 1149, provide the following information (organized by schedule for each enrollment window):

(a) The number of days in the enrollment window;

(b) The number of customers that enrolled on each day of the enrollment window by submitting a Change of Service Election Declaration or otherwise (e.g., day one, three customers; day two, one customer, etc.).

Response to NAES Data Request 5.36

(a) In accordance with OAR 860-038-0275(2), "Electric companies must allow retail electricity customers that are eligible for direct access at least five business days after the Announcement Date to choose service under a cost-of-service rate option or to purchase electricity from either an electricity service supplier through direct access or an electric company through a standard rate offer." The five business day enrollment window applies to customers requesting the one year option and receiving service under Delivery Schedules 23/723, 28/728, 30/730, 41/74, 47/747, 48/748, 51/751, 52/752, 53/753, 54/754 and 76R/776R.

The Company has extended the enrollment period to three weeks for those customers electing the multi-year options who currently receive service under Delivery Schedules 47, 48, 747, or 748 or Delivery Schedules 30, 47 and/or 48 or 730, 747 and/or 748 under a single corporate entity with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW.

(b) PacifiCorp does not track the number of daily enrollments received during the enrollment period.

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.37

NAES Data Request 5.37

Reference PAC/800, Ridenour/4:14-15, testifying: "An ESS has four weeks from the first day of the open enrollment window to submit a DASR".

(a) Is it Ms. Ridenour's position that customers frequently enroll on the "first day of the open enrollment window"?

(b) If yes, please provide all evidence supporting Ms. Ridenour's position.

Response to NAES Data Request 5.37

(a) A customer may enroll on the first day of the open enrollment window. Ms. Ridenour has not studied and does not have an opinion on when during the open enrollment window customers have submitted their Change of Service Election Declaration (CSED) forms.

(b) Please refer to the Company's response to subpart (a) above.

Exhibit: Noble Solutions/206

Description: PacifiCorp's Response to Noble Solutions' Data Request 5.39

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.39

NAES Data Request 5.39

Reference PAC/800, Ridenour/4: 10-11, testifying: "Requiring timely submission of a DASR is important to monitoring the enrollment in the program".

(a) Does Ms. Ridenour disagree that the Company's Rule 22 specifically requires: "Consumers wishing to change their Service Election from Cost-Based Service to Direct Access or Standard Offer Service must do so by submitting a written Change of Service Election Declaration (CSED) during an annual declaration window".

(b) Please explain why PacifiCorp cannot monitor enrollment in the program from the Change of Service Election Declarations that PacifiCorp receives from the customer at the time that it enrolls during the election window.

(c) Does Ms. Ridenour agree that if a customer fails to submit a CSED to the Company during the enrollment window, the Company will not allow the customer into the direct access program?

(d) Does Ms. Ridenour assert that if the Company received CSEDs that represented in excess of 175 aMW of cumulative enrollment in the five-year program that the Company would continue to accept further CSEDs and allow additional customers in excess of 175 aMW into the program? If yes, please explain why.

Response to NAES Data Request 5.39

(a) Yes.

(b) The submission of a Change of Service Election Declaration (CSED) indicating a five-year direct access election is no guarantee that a Direct Access Service Request (DASR) will be received for that customer. Until the DASR is received the Company cannot enroll the customer in the five-year program.

(c) Yes. The Company will not switch a customer from direct access / standard offer to cost based service or vice versa without the customer's written or electronic authorization in the form of a CSED as indicated in the Company's Rule 21, Section VII.A.

(d) The Company does not place a customer on the five-year program based on the receipt of a CSED indicating the five-year program. As indicated above, the receipt of a CSED indicating a choice of the five-year direct access election is no guarantee that a corresponding DASR will be received. No customer will be placed on the five-year program until the DASR is received for that customer. Enrollment in the five-year program will be first come, first served based on the receipt of the DASRs. The Company will continue to accept CSEDs that indicate a choice of the five-year program until the total load of customers enrolled in the program through the receipt of a DASR reaches the program cap.

Exhibit: Noble Solutions/207

Description: PacifiCorp's Response to Noble Solutions' Data Request 5.41 and attachments

UE 296 / PacifiCorp
August 17, 2015
NAES Data Request 5.41

NAES Data Request 5.41

Please provide currently effective copies of the Company's Rule 21; Rule 22; Schedules 294, 295, and 296; the Company's DASR form; and the Company's CSED form.

Response to NAES Data Request 5.41

Please refer to Attachment NAES 5.41-1 for copies of the requested rules and schedules.

The Direct Access Service Request (DASR) form is not a paper form and must be submitted electronically by the ESS. This requirement is from OAR 860-038-0445(5), which requires DASRs conform to industry electronic data interchange (EDI) protocols. All ESS's must submit the same data and in the same EDI format as provided in Attachment NAES 5.41-2. All ESS's must go through EDI testing with the Company before it is certified by the Company. Testing includes adding and dropping of customers. The DASR submission is initiated by the ESS.

The Company has two Change of Service Election Declaration (CSED) forms, one for the standard one year option and another for the three year option. The Company's CSED forms are provided in Attachment NAES 5.41-3.

Purpose

The purpose of this Schedule is to adjust prices to reflect the results of the ongoing valuation method under OAR 860-038-0140.

Applicable

This Schedule is applicable to all Nonresidential Consumers receiving service under Schedule 220, Standard Offer Service, Schedule 230, Emergency Supply Service or the applicable Direct Access Service Schedule except consumers electing a multi-year opt-out.

Transition Adjustment

The transition adjustment is the difference between the estimated market value of the electricity that is freed up when a customer chooses to leave Cost-Based Supply Service for Direct Access versus the Company's regulated price. The estimated market value of the freed up electricity is determined by running two system simulations – one simulation with the Company serving the Direct Access Consumer and one simulation with the Company not serving the Direct Access Consumer. The difference between the two scenarios is analyzed to calculate the impact on the Company's total system. The impacts are then used to determine the Weighted Market Value of the energy, which is then compared to the Customer's energy-only tariff schedule rate.

The Transition Adjustment amounts are shown below for each rate schedule, by Heavy Load Hours (HLH), Light Load Hours (LLH) and voltage level, where applicable. Adjustments are expressed on a cents per kilowatt-hour basis.

Notification of Transition Adjustment

Based on the announcement date defined in OAR 860-038-275, the Company will post on its website (www.pacificpower.net) the monthly on- and off-peak transition adjustment for each delivery service schedule shown on Schedule 201 for each applicable delivery voltage level for Nonresidential Consumers for the 12-month period from January 1 through December 31 of the calendar year subsequent to the announcement date.

Balancing Account

Beginning January 2006, the Company will accrue in this account, the costs, resulting from changes in the forward price curve that occurred during the open enrollment window, the load actually participating in Direct Access as compared to the assumed level of participation in the simulations, and any executed energy transactions resulting from significant load departure, if such costs exceed $250,000. The Company shall accrue interest on transition adjustment balances, whether positive or negative, at the Company's authorized rate of return. Amounts in this account will be recovered through an adjustment schedule from all consumers eligible for direct access.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

One-Year Option - Transition Adjustments (cents/kWh)

	23/723 Secondary		23/723 Primary		28/728 Secondary		28/728 Primary		30/730 Secondary	
	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH
Jan-15	-1.330	-0.940	-1.470	-1.103	-1.227	-0.851	-1.351	-0.956	-1.417	-0.972
Feb-15	-1.160	-0.804	-1.323	-0.961	-1.074	-0.710	-1.209	-0.825	-1.203	-0.830
Mar-15	-0.764	-0.577	-0.903	-0.764	-0.677	-0.484	-0.789	-0.601	-0.809	-0.616
Apr-15	-0.088	0.009	-0.310	-0.114	-0.011	0.107	-0.144	0.015	-0.144	-0.022
May-15	0.218	0.252	0.077	0.116	0.319	0.348	0.236	0.287	0.170	0.229
Jun-15	0.251	0.534	0.092	0.402	0.340	0.642	0.205	0.553	0.199	0.515
Jul-15	-1.024	-0.264	-1.175	-0.408	-0.942	-0.171	-1.076	-0.229	-1.071	-0.264
Aug-15	-1.555	-0.546	-1.697	-0.718	-1.468	-0.467	-1.573	-0.518	-1.585	-0.552
Sep-15	-1.241	-0.436	-1.394	-0.587	-1.140	-0.358	-1.236	-0.454	-1.270	-0.460
Oct-15	-0.740	-0.495	-0.903	-0.611	-0.655	-0.413	-0.768	-0.530	-0.783	-0.548
Nov-15	-1.010	-0.659	-1.157	-0.789	-0.875	-0.571	-1.018	-0.700	-1.046	-0.701
Dec-15	-1.220	-0.880	-1.374	-1.039	-1.154	-0.793	-1.279	-0.888	-1.255	-0.918

	30/730 Primary		41/741 Secondary		41/741 Primary		47/747,48/748 Secondary		47/747,48/748 Primary	
	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH
Jan-15	-1.407	-1.020					-1.409	-0.982	-1.605	-1.172
Feb-15	-1.242	-0.883					-1.236	-0.848	-1.434	-1.043
Mar-15	-0.854	-0.663					-0.835	-0.634	-1.046	-0.816
Apr-15	-0.188	-0.065	-0.072	0.017	-0.149	-0.060	-0.141	-0.056	-0.351	-0.239
May-15	0.139	0.200	0.281	0.336	0.204	0.259	0.133	0.212	-0.049	0.039
Jun-15	0.133	0.482	0.276	0.589	0.199	0.512	0.143	0.469	-0.042	0.284
Jul-15	-1.103	-0.324	-0.966	-0.118	-1.043	-0.195	-1.086	-0.281	-1.306	-0.426
Aug-15	-1.626	-0.612	-1.465	-0.384	-1.542	-0.461	-1.602	-0.552	-1.813	-0.704
Sep-15	-1.313	-0.515	-1.182	-0.317	-1.259	-0.394	-1.296	-0.472	-1.500	-0.638
Oct-15	-0.826	-0.609	-0.705	-0.430	-0.782	-0.507	-0.801	-0.550	-1.013	-0.754
Nov-15	-1.052	-0.752					-1.081	-0.727	-1.276	-0.900
Dec-15	-1.327	-0.962					-1.279	-0.899	-1.524	-1.126

	47/747,48/748 Transmission		51/751		52/752		53/753		54/754	
	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH	HLH	LLH
Jan-15	-1.633	-1.227	-1.210	-0.792	-1.910	-1.492	-3.214	-2.796	-2.512	-2.094
Feb-15	-1.456	-1.116	-1.038	-0.674	-1.738	-1.374	-3.041	-2.678	-2.339	-1.976
Mar-15	-1.077	-0.894	-0.649	-0.447	-1.349	-1.147	-2.653	-2.450	-1.951	-1.749
Apr-15	-0.437	-0.316	0.029	0.145	-0.672	-0.555	-1.975	-1.858	-1.273	-1.156
May-15	-0.137	-0.080	0.340	0.398	-0.360	-0.302	-1.664	-1.605	-0.962	-0.903
Jun-15	-0.134	0.186	0.346	0.674	-0.354	-0.027	-1.657	-1.330	-0.955	-0.628
Jul-15	-1.337	-0.543	-0.896	-0.081	-1.596	-0.781	-2.899	-2.084	-2.198	-1.382
Aug-15	-1.811	-0.815	-1.402	-0.358	-2.102	-1.058	-3.405	-2.361	-2.704	-1.660
Sep-15	-1.521	-0.731	-1.103	-0.266	-1.803	-0.966	-3.106	-2.269	-2.405	-1.567
Oct-15	-1.056	-0.817	-0.612	-0.364	-1.312	-1.065	-2.615	-2.368	-1.913	-1.666
Nov-15	-1.306	-0.953	-0.884	-0.507	-1.584	-1.207	-2.887	-2.510	-2.186	-1.809
Dec-15	-1.552	-1.180	-1.104	-0.745	-1.804	-1.445	-3.107	-2.748	-2.405	-2.047

TRANSITION ADJUSTMENT
THREE-YEAR COST OF SERVICE OPT-OUT

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to opt-out of the Company's Cost-Based Supply Service Schedule 201 for a minimum three-year period and who currently receive Delivery Service under Schedules 47, 48, 747, or 748 or Consumers who receive service under Delivery Service Schedules 30, 47 and/or 48 or 730, 747 and/or 748 under a single corporate entity with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW.

Total Eligible Load

A total load of 200 MW will be accepted under this schedule.

Transition Adjustment

The Transition Adjustments for each three-year period are listed below by applicable enrollment period.

The annual Transition Adjustment amounts are shown below for each Delivery Service rate schedule, by voltage level, for Heavy Load Hours (HLH) and Light Load Hours (LLH). Adjustments are expressed on a cents per kilowatt-hour basis.

Energy Supply

The Consumer must elect to purchase energy from an ESS (Direct Access Service) for all of the Consumer's Points of Delivery under this schedule.

Notification of Transition Adjustment

Based on the announcement date defined in OAR 860-038-275, the Company will post on its website (www.pacificpower.net) the transition adjustment for each eligible delivery service schedule shown on Schedule 201 for each applicable delivery voltage level for Nonresidential Consumers for the 3-year period from January 1 of the calendar year subsequent to the announcement date.

Balancing Account

Beginning January 2007, the Company will accrue in this account, the costs, resulting from changes in the forward price curve that occurred during the open enrollment window, the load actually participating in Direct Access as compared to the assumed level of participation in the simulations, and any executed energy transactions resulting from significant load departure, if such costs exceed $250,000. The Company shall accrue interest on the transition adjustment balances, whether positive or negative, at the Company's authorized rate of return. Amounts in this account will be recovered through an adjustment schedule from all consumers eligible for direct access.

(continued)

Three-Year Option - Transition Adjustments (cents/kWh)

Adjustments for Consumers Electing This Option for 2013-2015 (No New Service)

	30/730 Secondary		30/730 Primary	
	HLH	LLH	HLH	LLH
2013	-0.514	-0.457	-0.564	-0.509
2014	-1.148	-0.840	-1.168	-0.902
2015	-1.313	-1.178	-1.325	-1.221

	47/747, 48/748 Secondary		47/747, 48/748 Primary		47/747, 48/748 Transmission	
	HLH	LLH	HLH	LLH	HLH	LLH
2013	-0.507	-0.454	-0.668	-0.621	-0.742	-0.701
2014	-1.335	-0.942	-1.331	-1.037	-1.363	-1.083
2015	-1.509	-1.324	-1.498	-1.373	-1.505	-1.407

Adjustments for Consumers Electing This Option for 2014-2016 (No New Service)

	30/730 Secondary		30/730 Primary	
	HLH	LLH	HLH	LLH
2014	-0.437	-0.275	-0.486	-0.344
2015	-0.786	-0.531	-0.812	-0.593
2016	-0.931	-0.935	-0.960	-0.979

	47/747, 48/748 Secondary		47/747, 48/748 Primary		47/747, 48/748 Transmission	
	HLH	LLH	HLH	LLH	HLH	LLH
2014	-0.447	-0.158	-0.544	-0.391	-0.648	-0.474
2015	-0.875	-0.534	-0.913	-0.662	-0.978	-0.704
2016	-1.042	-1.199	-1.071	-1.002	-1.111	-1.075

Adjustments for Consumers Electing This Option for 2015-2017

	30/730 Secondary		30/730 Primary	
	HLH	LLH	HLH	LLH
2015	-0.715	-0.448	-0.757	-0.494
2016	-0.781	-0.397	-0.793	-0.409
2017	-0.969	-0.598	-0.978	-0.596

	47/747, 48/748 Secondary		47/747, 48/748 Primary		47/747, 48/748 Transmission	
	HLH	LLH	HLH	LLH	HLH	LLH
2015	-0.758	-0.415	-0.948	-0.659	-0.998	-0.744
2016	-0.844	-0.449	-1.025	-0.624	-1.061	-0.694
2017	-1.097	-0.646	-1.224	-0.845	-1.246	-0.895

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to opt-out of the Company's Cost-Based Supply Service Schedule 201 for a five-year period and who currently receive Delivery Service under Schedules 47, 48, 747, or 748 or Consumers who receive service under Delivery Service Schedules 30, 47 and/or 48 or 730, 747 and/or 748 under a single corporate entity with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW.

Total Eligible Load

A total of 175 aMW will be accepted under this schedule.

Transition Adjustment

The Transition Adjustments for each five-year period are listed below by applicable enrollment period. At the end of the applicable five-year period, consumers who have elected this option will no longer be subject to Transition Adjustments.

The annual Transition Adjustment amounts are shown below for each Delivery Service rate schedule, by voltage level. Transition Adjustments are expressed on a cents per kilowatt-hour basis.

Consumer Opt-Out Charge

The Consumer Opt-Out Charge will be applicable for the five-year enrollment period. At the end of the applicable five-year period, consumers who have elected this option will no longer be subject to the Consumer Opt-Out Charge, Transition Adjustments or to charges in Schedule 200, Base Supply Service.

Energy Supply

The Consumer must elect to purchase energy from an ESS (Direct Access Service) for all of the Consumer's Points of Delivery under this schedule.

Return to Cost-Based Service

Consumers electing service under this schedule must give the Company not less than four years' notice to return to Standard Offer Service or Cost-Based Service as described in Section VII of Rule 21 of this tariff. If a Consumer gives notice to return within the five-year transition period, the Consumer Opt-Out Charge will cease to apply to that consumer after the date of the official notice; Transition Adjustments will continue to apply during the remainder of the applicable period.

(continued)

Notification of Transition Adjustment and Consumer Opt-Out Charges

Based on the announcement date defined in OAR 860-038-275, the Company will post on its website (www.pacificpower.net) the Transition Adjustment and Consumer Opt-Out Charge for each eligible Delivery Service schedule shown on Schedule 201 for each applicable delivery voltage level for Nonresidential Consumers for the five-year period from January 1 of the calendar year subsequent to the announcement date. The Consumer Opt–Out Charge may be subject to later adjustments pursuant to commission-approved rate changes related to Schedule 200, Base Supply Service.

Balancing Account

The Company will accrue in this account, the costs, resulting from changes in the forward price curve that occurred during the open enrollment window, the load actually participating in Direct Access as compared to the assumed level of participation in the simulations, and any executed energy transactions resulting from significant load departure, if such costs exceed $250,000. The Company shall accrue interest on the transition adjustment balances, whether positive or negative, at the Company's authorized rate of return. Amounts in this account will be recovered through an adjustment schedule from all consumers eligible for direct access.

(continued)

Adjustments for Consumers Electing This Option for Service Beginning January 1, 2016

The Monthly Billing will be the Transition Adjustments plus the Consumer Opt-Out Charge as specified below by Delivery Service Schedule.

Transition Adjustments (cents/kWh)

	730 Secondary	730 Primary	747, 748 Secondary	747, 748 Primary	747, 748 Transmission
2016	-	-	-	-	-
2017	-	-	-	-	-
2018	-	-	-	-	-
2019	-	-	-	-	-
2020	-	-	-	-	-

Consumer Opt-Out Charge (cents/kWh)

	730 Secondary	730 Primary	747, 748 Secondary	747, 748 Primary	747, 748 Transmission
2016-2020	-	-	-	-	-

I. General Terms

A. Responsibility for Electric Purchases

ESSs are responsible for purchasing sufficient amounts of Electricity to meet the electric power needs of their Direct Access Consumers and the delivery of such purchases to designated receipt points as arranged with the Company through a Scheduling ESS.

B. Load Aggregation for Procuring Electric Power

Consumers or ESSs may aggregate individually metered electric loads for the purpose of procuring Electricity from ESSs, and only for that purpose. Aggregation will not be used to compute the Company's charges or to determine Tariff applicability.

C. Split Loads Not Allowed

Consumers requesting Direct Access Services may not partition the electric loads at a point of delivery among Service Elections or Service Options. The entire load at a point of delivery must be nominated to only one set of Service Elections or Service Options.

D. Master Metered Consumers

Individual master-metered Direct Access Consumers who provide sub-metered tenant billings must participate in Direct Access as a single account. A master-metered Direct Access Consumer may not partition the electric loads of a single master meter among several Service Elections or Service Options.

E. Limitation of Liability

1. The Company's obligations with respect to the continuity and quality of Delivery Service, Billing Services and other Electricity Services are covered by, subject to, and limited by Rules 10 and 14 of this Tariff.

2. To the extent that a Consumer takes service from an ESS or Scheduling ESS, the Company has no obligations to the Consumer with respect to the services provided by the ESS or Scheduling ESS.

3. The Company is neither bound by, nor will it enforce, contracts between an ESS and a Consumer or contracts between an ESS and a Scheduling ESS. Additionally, the Company will not mediate disputes between an ESS and a Consumer or between an ESS and a Scheduling ESS.

4. In no event shall the Company be liable for damages, claims or costs of any kind arising out of or related to an ESS' failure to adhere to the requirements, practices, and procedures set forth in this Tariff or the ESS Service Agreement.

(continued)

I. **General Terms** (continued)

E. **Limitation of Liability** (continued)

5. In no event shall the Company be liable for damages, claims or costs of any kind arising out of or related to a Scheduling ESS' failure to adhere to the requirements, practices, and procedures set forth in this Tariff or the Scheduling ESS Operating Agreement.

6. The Company shall not be liable to an ESS, a Scheduling ESS or any third party under any theory of recovery of liability whether based in contract, in tort (including negligence and strict liability), under warranty, indemnity, or otherwise, for any indirect, special, incidental or consequential damages whatsoever, including, without limitation, any loss of profits or other business interruption damages arising under this Tariff, the ESS Service Agreement or the Scheduling ESS Operating Agreement.

7. The Company is not responsible for liabilities or claims against Consumers, ESSs, or Scheduling ESSs.

II. **Consumer Inquiries**

A. **Consumer Inquiries Related to Service Elections**
For Consumers requesting information on Direct Access Service, the Company will make available consumer information explaining the Consumer's choices for electricity services and the procedures and forms needed to implement these services.

B. **Inquiries Related to Suppliers**
For Consumers requesting such information, the Company will provide a list of ESSs eligible to provide electricity services in the Company's service territory. The list will be presented in a neutral format that does not unfairly emphasize an affiliated ESS. To satisfy its obligations under this rule, the Company may direct Consumers to an ESS list maintained and published by the Commission.

C. **Information Provided to New Consumers**
New Consumers contacting the Company will receive general information concerning their choices for Electricity Services.

D. **Consumer Inquiries Concerning Billing**
The Company will respond to inquiries from Direct Access Consumers concerning charges for services provided by the Company. Consumer inquiries regarding charges for services provided by the ESS will be directed to the ESS. The Company will work with the Consumer and ESS to resolve inquiries that involve services provided by both the Company and the ESS.

E. **Consumer Inquiries Related To Emergency Situations and Outages**
The Company will respond to all inquiries related to distribution and transmission service, emergency system conditions, outages, and safety situations. Direct Access Consumers contacting ESS with such inquiries should be referred to the Company. ESSs performing ESS consolidated billing must show the Company's phone number on their bills for use in emergencies.

(continued)

III. Information Provided to ESSs

A. Pre-Enrollment Usage Information
At the written request of the Consumer, account-specific usage information, including twelve (12) months of usage history when available, will be provided to the Consumer or an ESS. The Company will charge a fee for providing pre-enrollment usage information as specified in Schedule 300.

B. Pre-Enrollment Payment History
At the written request of the Consumer, the Company will provide a letter describing the Consumer's payment history to the Consumer or to an ESS. The payment history will reflect the most recent twelve (12) months, to the extent that the information is available. The Company will charge a fee for providing a pre-enrollment payment history as specified in Schedule 300.

C. Implied Consent To Release Usage Information
By agreeing to take Direct Access Service from an ESS, the Consumer consents to the release by the Company to the Consumer's ESS or Scheduling ESS of historical usage data and metering information necessary for the ESS or Scheduling ESS to satisfy their responsibilities in scheduling, billing, settlement, and other functions.

IV. ESS Service Requirements

A. ESS Service Agreement

1. An ESS must have in force a valid ESS Service Agreement with the Company in order to provide Competitive Electricity Services to Direct Access Consumers within the Company's service territory.

2. The Company's ESS Service Agreement shall be in a form specified by the Company as approved by the Commission and accompanied by payment of the applicable processing fee stated in Schedule 600.

3. An ESS must renew its ESS Service Agreement with the Company annually.

4. The Company will execute an ESS Service Agreement with any ESS meeting the requirements stated in this Tariff according to the terms of the ESS Service Agreement then in effect.

B. Requirements
To provide Competitive Electricity Services to Direct Access Consumers within the Company's service territory, the ESS must be certified by the Commission and:

1. Abide by North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) standards and requirements.

2. Have in force a valid ESS Service Agreement with the Company.

(continued)

IV. ESS Service Requirements (continued)

B. Requirements (continued)

3. Satisfy the Company's creditworthiness requirements as specified in Section XIII of this Rule.

4. Be certified as a Scheduling ESS and have in place a valid Scheduling ESS Operating Agreement with the Company or designate as its scheduling entity a certified Scheduling ESS with a valid Scheduling ESS Operating Agreement with the Company.

5. Before an ESS may offer consolidated ESS billing services, the ESS must demonstrate the ability to perform the functions required by this Tariff and the Commission's rules. The Company will continue to provide the billing services until the ESS has satisfied this obligation. The ESS' failure to complete such compliance testing will not affect its ability to provide Competitive Electricity Services to Direct Access Consumers.

6. Satisfy applicable Company Electronic Data Exchange requirements, including:

   a. The ESS must complete all necessary electronic interfaces for the ESS and the Company to communicate for Direct Access Service Requests (DASR), billing and other communications.
   b. The ESS must have the capability to exchange data with the Company via the Internet. Alternative arrangements may be allowed upon mutual agreement between the Company and ESS.
   c. The ESS must have the capability to perform Electronic Data Interchange (EDI), and enter into appropriate agreements related thereto, if the ESS will be offering ESS consolidated billing services.

C. Suspension or Termination of ESS Service

1. Criteria

The Company may suspend or terminate an ESS' contractual authorization to provide Competitive Electricity Services to Direct Access Consumers in the Company's service area and transfer these Consumers to Emergency Default Service upon satisfaction of the Company's deposit requirement if:

a. The ESS has materially failed to meet its obligations under the terms of the Company's ESS Service Agreement (including applicable tariffs) so as to constitute an Event of Default and the Company exercises a contractual right to terminate the agreement.

b. The ESS engages in unauthorized use of electricity or a Consumer engages in unauthorized use of electricity and the ESS knew or should have known about it.

c. The ESS' Scheduling ESS is suspended or terminated as set forth in Section V. (C) of this Rule.

d. The Commission otherwise directs.

(continued)

IV. ESS Service Requirements (continued)

C. Suspension or Termination of ESS Service (continued)

2. Appeal

If the Company suspends or terminates an ESS' authorization to provide Competitive Electricity Services because the ESS materially failed to meet its obligations under the terms of the Company's ESS Service Agreement, the ESS' rights of appeal will be as specified in the Agreement. If the Company suspends or terminates the ESS' authorization for any other reason, the ESS may appeal the decision to the Commission.

If the Company provides a written notice to an ESS regarding suspension or termination of service, the Company will promptly provide copies of the notice to affected consumers.

V. Scheduling ESS Service Requirements

A. Scheduling ESS Operating Agreement

1. The Scheduling ESS must have in force a valid Scheduling ESS Operating Agreement with the Company in order to perform scheduling services for Consumers in the Company's service territory.

2. The Company's Scheduling ESS Operating Agreement shall be in a form specified by the Company as approved by the Commission and accompanied by payment of the applicable processing fee stated in Schedule 600.

3. The Scheduling ESS must renew on an annual basis its Scheduling ESS Operating Agreement with the Company.

4. The Company will execute a Scheduling ESS Operating Agreement with any ESS meeting the requirements stated in this Tariff according to the terms of the Scheduling ESS Operating Agreement then in effect.

B. Requirements

To perform scheduling services for Consumers within the Company's service territory, a Scheduling ESS must be certified as a Scheduling ESS by the Commission or be a control area operator and:

1. Have in force a valid Scheduling ESS Operating Agreement with the Company.

2. Comply with all Western Electricity Coordinating Council (WECC) scheduling and reliability criteria.

3. Meet all generally accepted regional scheduling practices unless otherwise modified by the Commission.

(continued)

V. Scheduling ESS Service Requirements (continued)

B. Requirements (continued)

4. Maintain around-the-clock, seven-day-a-week dispatch facilities.

5. Identify each of the Consumers which they are authorized to represent as a Scheduling ESS and confirm that the necessary metering requirements are met for the transmitting of information to the Company.

C. Suspension or Termination of Scheduling ESS Service

1. Criteria

The Company may suspend or terminate a Scheduling ESS' contractual authorization to provide scheduling services for Direct Access Consumers in the Company's service area if:

a. The Scheduling ESS has materially failed to meet its obligations under the terms of the Scheduling ESS Operating Agreement (including applicable tariffs) so as to constitute an event of default and the Company exercises a contractual right to terminate the agreement.

b. The Scheduling ESS ceases to perform by failing to provide schedules when schedules are required.

c. The Commission otherwise directs.

2. Appeal

If the Company suspends or terminates a Scheduling ESS' authorization to provide services because the Scheduling ESS materially failed to meet its obligations under the terms of the Scheduling ESS Operating Agreement, the Scheduling ESS' rights of appeal will be as specified in the Agreement. If the Company suspends or terminates the Scheduling ESS' authorization for any other reason, the Scheduling ESS has the right to appeal the decision to the Commission.

VI. Direct Access Service Election and Supplier Choice

A. Direct Access Service Request (DASR)

Changes in a Nonresidential Consumer's Service Election or ESS require a DASR. A Nonresidential Consumer may only switch to Direct Access Service or change ESS if the new ESS submits a DASR as described in this Section. A DASR is submitted pursuant to the terms and conditions of the Company's ESS Service Agreement and this Rule. A DASR will be used to define the Competitive Electricity Services that the ESS is providing the Consumer.

(continued)

VI. Direct Access Service Election and Supplier Choice (continued)

B. Form of DASR

A DASR must be submitted in a format provided by the Company. A separate DASR must be submitted for each point of delivery. A DASR must be separate and distinct from any other form or offer.

C. Rejection of DASR

The Company may reject a DASR if:

1. The DASR is in an improper form or is incomplete.
2. The requested effective date is less than 13 business days after the date the DASR is submitted.
3. The information provided by the ESS on the DASR is false or inaccurate in any material respect.
4. The DASR is submitted by a person other than the authorized ESS.
5. The designated ESS and/or its Scheduling ESS are not authorized to provide the requested services within the Company's service territory as described in this Tariff and in the Commission Rules.
6. The Consumer is not entitled to Direct Access Service because it is a Residential Consumer or because it is a Nonresidential Consumer electing to switch to Direct Access Service at a time which is prohibited by this Tariff or Commission rule or Order.

D. DASR Processing

1. The Company will provide a DASR status notification informing an ESS as to whether the DASR has been accepted or rejected within three business days of the day on which the DASR is received. If accepted, the switch date determined in accordance with this Section, will be sent to the ESS, the former ESS if applicable, and the Consumer. If a DASR is rejected, the Company will provide the reason(s) for the rejection.
2. Upon request, the Company will provide timely updates on the status of the DASR processing to the submitting ESS and Consumer.
3. If the Company receives a DASR while it is processing a DASR applicable to a Consumer, the second DASR will supercede the first. The processing period for the DASR will be restarted with receipt of the second DASR.

(continued)

VI. Direct Access Service Election and Supplier Choice (continued)

E. Implementation of the DASR

If a submitted DASR complies with the requirements of this Rule, the DASR will be accepted and scheduled for implementation. Implementation will begin at midnight on the day of implementation. Pending final acceptance and implementation of a DASR, the Consumer's incumbent ESS is responsible for providing Consumer the same Competitive Electricity Services it has historically provided.

1. Transmission Service

Implementation of a DASR will not take place until the Scheduling ESS certifies the commencement of all transmission services related to the service request.

2. No Meter Change Required

Subject to the provision of subsection VI. (E)(1) above, accepted DASRs that do not require a meter change will be switched over on the effective date as stated on the DASR.

3. Meter Change Required

Accepted DASRs that require a meter change by the Company may be served using existing acceptable metering equipment. Billing and settlements for such Consumers will be based on load profiles specified by the Company until standard metering equipment is installed. Consumers seeking Direct Access Service will receive the same priority for changes in standard metering equipment as other Consumers.

4. Commencement of Direct Access

The Company will begin receiving DASRs upon approval of this Tariff. If the Company receives a volume of DASRs that exceeds the amount that the Company can process in an accurate and timely manner, the Company will promptly notify the Commission and will promptly process the DASRs it receives on a nondiscriminatory basis.

5. Change Requiring Special Meter Read

If the effective date for a DASR submitted under this Section does not coincide with the Company's established meter reading schedule, the Consumer will pay to the Company the applicable charge for off-cycle meter reading specified in Schedule 300. The Company's DASR form will provide Consumers the option of switching on a date that coincides with the Company's established meter reading schedule.

6. Schedule Change By Mutual Agreement

The Company, ESS, and Consumer, by mutual agreement, may agree to a different service change date for the service changes requested in a DASR. The Company will retain documentation of a schedule change by mutual agreement with its documentation of the original DASR for a period of three (3) years.

(continued)

VI. Direct Access Service Election and Supplier Choice (continued)

F. DASR Processing Fee
The Company will assess a charge for processing DASRs, as specified in Schedule 600, if the DASR is accepted. This charge will be billed to the ESS.

VII. Standard Offer and Cost-Based Service

A. Consumer Authorization
Except in the case of a Nonresidential Consumer taking Emergency Default Service, the Company will not switch a Nonresidential Consumer from Direct Access to Standard Offer or Cost-Based Service, as applicable, or among the Company's Standard Offer Service rate options without the Consumer's written authorization or electronic authorization in a form acceptable to Company.

B. Form of Authorization
The written or electronic authorization must be in a format provided by the Company and shall include, at a minimum: (1) the Consumer's name, current account number and unique location identifier, if available; (2) the service address and the Consumer's mailing address; (3) the type of service and/or the Standard Offer Service rate option being purchased; (4) a designation of the Company as the new supplier; (5) the Consumer's choice of Billing Services; (6) identification and explanation of any nonrecurring charges associated with the Consumer's decision to take service from the Company; (7) a statement that the Consumer is authorized to make the change and authorizes the Company to provide service; and (8) the Consumer's signature or electronic authorization, and title.

C. Implementation

1. The request for Standard Offer or Cost-Based Service will be subject to all Tariffs for new Company service, including applicable deposit provisions stated in Rule 9.

2. The Consumer must give the Company at least five business days notice before the date it wishes to switch to default Standard Offer Service. Additional notice periods may apply to other Standard Offer Service rate options as set forth in this Tariff.

3. A Consumer receiving Standard Offer or Direct Access Service may return to Cost-Based Service only by complying with the returning service requirements stated in Schedule 201. If the Company receives a request for Cost-Based Service from a Consumer ineligible for such service under this Rule, then the Company will notify the Consumer of its ineligibility and request a new authorization from the Consumer for Standard Offer Service.

4. A Consumer receiving Direct Access Service under the Five-Year Cost of Service Opt-Out must give the Company not less than four years' notice to return to Standard Offer Service or Cost-Based Service. Such notices will be binding. The return to Standard Offer or Cost-Based Service will begin on January 1 of the calendar year following the end of the four-year period.

(continued)

VII. Standard Offer and Cost-Based Service (continued)

C. Implementation (continued)

5. Requests for Standard Offer Service that require a meter change by the Company may be served using existing acceptable metering equipment. Billing for such Consumers will be based on load profiles specified by the Company until standard metering equipment is installed. Consumers seeking Standard Offer Service will receive the same priority for changes in standard metering equipment as other Consumers.

6. If the change date does not coincide with the Company's established meter reading schedule, the Consumer will pay to the Company the applicable charge for off-cycle meter reading specified in Schedule 300. The Company will provide the option to Consumers of switching on a date that coincides with the Company's established meter reading schedule.

7. The Company and the Consumer may, by mutual agreement, agree to a different date for the service changes requested by the Consumer.

8. The Company will notify the Consumer's EES within 5 business days of the day that a Consumer requests Standard Offer or Cost Based Service.

D. Processing Fee

The Company will assess a charge to the Consumer for processing a request for Standard Offer or Cost-Based Service, as specified in Schedule 300.

VIII. ESS Notice of Discontinuance and Disconnection

A. In order to terminate service to a Consumer, an ESS must notify the Company at least 10 business days in advance of the proposed termination date, or if the Consumer has waived its right to the full notice period, the ESS must notify the Company of the planned termination at the same time it notifies the Consumer. The notice to the Company must include: (1) the Consumer's name, account number, service location and, if applicable, the unique location identifier; (2) the earliest date for discontinuance; (3) necessary information applicable to the transfer of the Consumer's service; and (4) the reasons for discontinuance.

B. If a Consumer has failed to pay past due regulated charges, the Company retains all rights under OAR 860-021-0305, et seq. to disconnect or under OAR 860-021-0200 et seq. to refuse to offer service without a deposit.

(continued)

IX. Service Options

A. Consumer Selection or Change of Service Options

1. The Consumer may select or change Service Options, including Billing and Ancillary Service Options, by submitting a DASR as described in Section VI of this Rule or a written or electronic authorization for Standard Offer or Cost-Based Service as described in Section VII of this Rule. Additionally, a Consumer may change Billing Option to any option offered by their ESS by notifying the Company in writing. The change will be effective with the Consumer's next meter read date, but in no event will it be effective in less than five (5) business days.

2. The Consumer may not change Billing or Ancillary Service Options more frequently than once per billing cycle on the regularly scheduled meter read date.

B. Company-Initiated Change of Service Options

1. **When the Company may initiate a change**
   The Company may change the Service Options of a Direct Access Consumer in the following circumstances:

   a. The ESS notifies the Company that it no longer offers a service which the Consumer is taking from the ESS.

   b. The ESS materially fails to meet its obligations under the terms of the Company's ESS Service Agreement (including applicable tariffs) so as to constitute an Event of Default and the Company exercises a contractual right to terminate the portion of the Agreement related to the service.

2. **Process for Company-Initiated Change**

   a. The affected ESS and Direct Access Consumers will be notified that the Company is initiating a change in Service Options.

   b. The ESS or the affected Direct Access Consumer shall have the right to seek an order from the Commission restoring the ESS' provision of the affected Service Options.

   c. Upon termination of consolidated ESS billing pursuant to this section, the Company may deliver a separate bill for all Company charges that were not previously billed to the ESS.

(continued)

X. Emergency Default Service

A. Emergency Default Service

Emergency Default Service provides temporary service to Direct Access Consumers in unforeseen circumstances that prevent the Consumer from obtaining a valid supply of Electricity from their incumbent ESS. In circumstances specified in Section X. (B) below, the Company may unilaterally change the Service Election of a Direct Access Consumer to Emergency Default Service. Consumers may not elect Emergency Default Service. The Company will not transfer a Consumer to Emergency Default Service if the Consumer or ESS has failed to pay any overdue amounts, Time Payment amounts or other obligations related to Regulated Charges of the Company. The Company may require a deposit from the consumer prior to transferring a Consumer to Emergency Default Service.

B. When Invoked

The Company may transfer a Direct Access Consumer to Emergency Default Service if any of the following circumstances occur:

1. The Company is informed by the ESS or the Direct Access Consumer that the ESS is no longer providing service.

2. The ESS has been decertified by the Commission or receives a Commission order that otherwise prohibits the ESS from serving that Direct Access Consumer.

3. The ESS materially fails to meet its obligations under the terms of the Company's ESS Service Agreement (including applicable tariffs) so as to constitute an Event of Default and the Company exercises a contractual right to terminate or suspend service under the Agreement.

C. Automatic Termination of Emergency Default Service

Unless otherwise directed by the Consumer, the Company will switch a Consumer from Emergency Default Service to Default Standard Offer Service within five (5) business days of the Consumer's initial purchase of Emergency Default Service. In no event may a Consumer remain on Emergency Default Service for longer than twenty (20) business days.

(continued)

X. Emergency Default Service (continued)

D. Process for Switching Consumer to Emergency Default Service

1. If the Company switches a Consumer to Emergency Default Service, or determines that it will need to do so, the Company will send notices of the change or impending change to the incumbent ESS and to the Consumer.

2. If the effective date of the change to Emergency Default Service does not coincide with the Company's established meter reading schedule, the Consumer will pay to the Company the applicable charge for off-cycle meter reading specified in Schedule 300.

3. The ESS or the affected Direct Access Consumer shall have the right to seek an order from the Commission restoring the Direct Access Consumer's Service Election and/or the ESS' ability to provide services.

XI. Ancillary Services

A. Regulation and Frequency Response Service

1. Definition
Regulation and Frequency Response Service is the continuous balancing of resources and load so as to maintain a scheduled interconnection frequency within standards established by the North American Electric Reliability Council (NERC). If the Company provides this service, the Company will use generating capacity controlled by automatic generation control to match the Consumer's loads and resources on a real-time basis. Regulation and Frequency Response Service includes frequency regulation and voltage control services.

2. Terms and Conditions
Terms and conditions for Regulation and Frequency Response Service are established by the Company's applicable tariff approved by the FERC. Charges for Regulation and Frequency Response Service will be billed to the Consumer's Scheduling ESS.

3. Alternate Provision
A Direct Access Consumer must purchase Regulation and Frequency Response Service from the Company unless the Consumer or its Scheduling ESS makes alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. A Consumer electing such alternate provision of Regulation and Frequency Response Service must demonstrate that its alternative arrangements are comparable to service under the Company's applicable tariff approved by the FERC.

(continued)

XI. Ancillary Services (continued)

B. Emergency Imbalance Service

1. Definition

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy over a single hour. Energy Imbalance Service includes load shaping, load following, and energy balancing services.

2. Terms and Conditions

Terms and conditions for Energy Imbalance Service are established by the Company's applicable tariff approved by the FERC. Charges for Energy Imbalance Service will be billed to the Consumer's Scheduling ESS. The amount of energy imbalance is calculated for the entire load the Scheduling ESS is serving for an ESS.

3. Alternate Provision

A Direct Access Consumer must purchase Energy Imbalance Service from the Company unless the Consumer or its Scheduling ESS makes alternative comparable arrangements to prevent the occurrence of energy imbalances with the Company. The Consumer or its Scheduling ESS must demonstrate to the Company that such alternative arrangements will be effective in preventing energy imbalances with the Company.

C. Operating Reserve – Spinning Reserve Service

1. Definition

Spinning reserve serves load immediately in the event of a system contingency. Spinning Reserve Service is provided by generating units that are controlled by automatic generation control, on-line and loaded at less than maximum output. Upon the outage of a generation resource for which Spinning Reserve Service has been purchased, Spinning Reserve Service provides replacement capacity commencing immediately until the earlier of (a) the restoration of the resource to service or (b) the end of ten (10) full minutes after the occurrence of the outage.

2. Terms and Conditions

Terms and conditions for Operating Reserve – Spinning Reserve Service are established by the Company's applicable tariff approved by the FERC. Charges for Operating Reserve – Spinning Reserve Service will be billed to the Consumer's Scheduling ESS.

3. Alternate Provision

A Direct Access Consumer must purchase Spinning Reserve Service from the Company except to the degree that the Consumer or its Scheduling ESS makes alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. A Consumer electing such alternate provision of all or a portion of its Spinning Reserve Service obligation must demonstrate that its alternative arrangements are comparable to service under the Company's applicable tariff approved by the FERC.

(continued)

XI. Ancillary Services (continued)

D. Operating Reserve – Supplemental Reserve Service

1. Definition
Supplemental reserve serves load in the event of a system contingency within a short period of time. Supplemental Reserve Service is provided by generating units that are on-line and loaded at less than maximum output, by quick-start generation or by interruptible load. Upon the outage of a generation resource for which Supplemental Reserve Service has been purchased, Supplemental Reserve Service provides replacement capacity commencing ten (10) full minutes after the outage until the earlier of (a) the restoration of the resource to service or (b) the end of the first full hour immediately following the occurrence of the outage.

2. Terms and Conditions
Terms and conditions for Operating Reserve – Supplemental Reserve Service are established by the Company's applicable tariff approved by the FERC. Charges for Operating Reserve – Supplemental Reserve Service will be billed to the Consumer's Scheduling ESS.

3. Alternate Provision
A Direct Access Consumer must purchase Supplemental Reserve Service from the Company unless the Consumer makes alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. A Consumer electing such alternate provision of its Supplemental Reserve Service obligation must demonstrate that its alternative arrangements are comparable to service under the Company's applicable tariff approved by the FERC.

XII. Scheduling

A. The scheduling of resources and transmission and distribution usage with the Company under Direct Access Service will be performed only by a certified Scheduling ESS.

B. Each Scheduling ESS must provide schedules to the Company pursuant to the terms of the Company's applicable tariff approved by the FERC.

C. All scheduling must be performed in accordance with the Scheduling ESS Service Operating Agreement and with the Company's scheduling protocols.

(continued)

XIII. ESS Credit Requirements

A. Credit Review/Applicability

These standards apply to a Non-Scheduling ESS or Scheduling ESS (sometimes collectively referred to as ESSs in this Section) selling electric services available pursuant to direct access to one or more retail electricity Consumers. Each ESS must qualify on an individual basis. An ESS's participation in direct access is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement and/or Scheduling ESS Operating Agreement. The Company shall determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company shall enter into an ESS Service Agreement and/or Scheduling ESS Operating Agreement after ESS's credit has been established pursuant to this Section XIII, collateral has been obtained and ESS certification by the Commission is complete. The Company shall continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. Credit Exposure

An ESS must establish and maintain creditworthiness relative to the Company's Credit Exposure to the ESS. Credit Exposure shall include, but not be limited to, the expected liabilities described in Section 4(a) herein.

C. Establishment of Credit

An ESS must establish its creditworthiness as stated in this Section.

1. Creditworthiness Requirements

Each ESS, or guarantor, must demonstrate the Company's creditworthiness requirements by satisfying all of the criteria in Section XIII(C)(1). An ESS who cannot demonstrate the requirements of Section XIII. (C)(1) shall provide a collateral deposit as described in Section XIII. (C)(4) to establish credit.

a. Credit Evaluation

An ESS seeking to enter into a new ESS Service Agreement or new Scheduling ESS Operating Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application under this Section if the ESS's ESS Service Agreement or Scheduling ESS Operating Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice. The credit evaluation will be conducted by the Company.

(continued)

XIII. ESS Credit Requirements (continued)

C. Establishment of Credit (continued)

1. Creditworthiness Requirements (continued)

a. Credit Evaluation (continued)

This evaluation will be completed within ten (10) Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b. Required Credit Information

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three (3) years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c. Rating Agency

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d. Tangible Net Worth

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two (2) year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e. Credit History

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other Agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

(continued)

XIII. ESS Credit Requirements (continued)

C. Establishment of Credit (continued)

2. Unsecured Credit

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying requirements in Section XIII(C)(1) above, a maximum unsecured credit limit will be established by the Company according to the following table. The S&P and Moody's rating is based on the ESS's long-term senior unsecured debt rating. If an ESS is split rated, the applicable credit limit will be based on the lower debt rating.

S&P / Moody's Ratings	Unsecured Credit Limit
> A+ / A1	$15MM
=A / A2	$10MM
=A- / A3	$7MM
=BBB+ / Baa1	$5MM
=BBB / Baa2	$4MM
=BBB- / Baa3	$3MM
<BBB- / Baa3	$0MM

The Company may increase the maximum unsecured credit limit on a case by case basis in a consistent manner using accepted commercial credit standards and based on the following criteria: (1) financial performance; (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis.

3. Collateral Requirements

The ESS shall be required to post or increase collateral under any of the following conditions:

a. the ESS does not meet the minimum creditworthiness standards established in Section XIII. (C)(1) above;

b. the ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in Sections XIII. (C)(1) and (C)(5) and the ESS Service Agreement or Scheduling ESS Operating Agreement;

c. the ESS experiences a Material Adverse Change. A Material Adverse Change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations.; or

(continued)

XIII. ESS Credit Requirements (continued)

C. Establishment of Credit (continued)

3. Collateral Requirements (continued)

d. the Company's total Credit Exposure to the ESS exceeds the ESS's unsecured credit limit as established according to Section XIII. (C)(2) and/or any existing collateral deposit.

4. Collateral Deposits

If collateral is required under Section XIII. (C)(3), the ESS shall submit and maintain a collateral deposit as described in this Section.

a. Amount of Collateral Deposit

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) for ESSs billing consumers for services provided by the Company, three times the estimated maximum monthly consumer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next twelve (12) months;

(ii) for Scheduling ESSs, sixty (60) times the estimated maximum daily Potential Replacement Cost of scheduled energy. Potential Replacement Cost is estimated by multiplying the total amount of energy expected to be scheduled by the Scheduling ESS times the Company's estimate of market prices expected during the forthcoming sixty (60) days;

(iii) all other charges from the Company to an ESS as estimated over a ninety (90) day period; and

(iv) all invoiced and non-invoiced receivables due from the ESS.

(v) In all cases where a collateral deposit is required under this Section 4, the ESS's collateral deposit shall not be less than $500,000.

b. Form of Collateral Deposit

Collateral deposits shall be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

(continued)

XIII. ESS Credit Requirements (continued)

C. Establishment of Credit (continued)

4. Collateral Deposits (continued)

c. Collateral Deposit Payment Timetable

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement and/or Scheduling ESS Operating Agreement. Collateral deposit increases and/or adjustments must be received within two (2) calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five (5) days of expiration of a collateral deposit.

d. Interest on Cash Deposit

The Company shall pay interest on cash collateral deposits. Interest shall be calculated according to the interest rate prescribed in Rule 9.

5. On-going Maintenance of Credit

a. The Company may review the ESS's creditworthiness, credit limits and the Company's Credit Exposure on a daily basis according to the criteria described in this Section XIII. The Company may request an increase in the collateral deposit according to the method described in Section XIII. (C)(4)(a) above by providing notice to the ESS that an increase is required as the ESS enrolls additional Consumers, the ESS no longer satisfied the minimum criteria commensurate with its unsecured credit line as described in Sections XIII. (C)(1) and (C)(2) above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's Credit Exposure to the ESS increases.

b. To assure continued validity of established unsecured credit, the ESS shall promptly notify the Company if the ESS (i) experiences any Material Adverse Change; (ii) the ESS's long-term, senior unsecured debt rating is downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from non-scheduling to Scheduling or vice versa.

c. The ESS shall provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of Section XIII. (C)(1)(a); upon the occurrence of any event listed in Section XIII. (C)(5)(a) or (5)(b); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d. The ESS shall review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

(continued)

XIII. ESS Credit Requirements (continued)

C. Establishment of Credit (continued)

5. On-going Maintenance of Credit (continued)

e. All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required collateral deposit. The Company will notify the ESS of any such needed adjustments. During the first year of Direct Access Implementation, the initial collateral amount required shall be the minimum collateral amount for a period of not less than one year after the date on which the ESS enters into and signs an ESS Service Agreement and/or Scheduling ESS Operating Agreement.

6. Re-establishment of Credit

An ESS whose ESS Service Agreement or Scheduling ESS Operating Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in Section 1 or by the provision of a collateral deposit, or by other manner described in this Section XIII.

D. Additional Documents

The ESS shall execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

XIV. Dispute Resolution

A. Disputes By Consumers

A Consumer with concerns regarding charges or services provided by the Company should contact the Company's business center. If, after contacting the business center, the Consumer's concerns have not been satisfied, the Consumer should contact the Company's Consumer Appeal Line. An employee will investigate the dispute and make an attempt to resolve it within five days.

If the Consumer's dispute is not resolved after contacting the Consumer Appeal Line, the Consumer has the right to informally contact the Consumer Assistance Staff of the Commission. The Consumer has the right to file a formal complaint with the Commission. While a Consumer is proceeding with an informal or a formal review of a dispute, the Company will not terminate service, provided that any amounts not disputed are paid when due.

B. Disputes By ESSs

An ESS with concerns regarding charges or services provided by the Company in conjunction with the Company's ESS Service Agreement should contact the Company representative identified in the Agreement. The Company will attempt to informally resolve disputes. The Company or the ESS may initiate the dispute resolution process specified in the Agreement.

Service Election

Consumers wishing to change their Service Election from Cost-Based Service to Direct Access or Standard Offer Service must do so by submitting a written Change of Service Election Declaration (CSED) during an annual declaration window.

A CSED shall be in a form provided by the Company and shall be submitted either by FAX or e-mail.

If the Company receives multiple CSEDs during the annual declaration window as defined in OAR 860-038-270, the last CSED received will be implemented. Consumers may rescind a CSED during an annual declaration window.

The dates of the annual declaration window will be provided on the Company's web site and communicated to eligible customers through other means.

Company will post applicable Transition Adjustments on its web site at the commencement of the annual declaration window.

Company will post indicative transition adjustments 1 week and 2 months prior to the commencement of the annual declaration window. Indicative transition adjustments are estimates and are not used for the calculation of customer bills. Indicative transition adjustments are subject to change.

Enrollment Request Sample
814-1
Inbound

ST*814*000000001!	Beginning transaction segment identifying the transaction and sequence number.
BGN*13*ABC0001*20010329!	Request #0001 from ABC created on 3/29/01.
N1*8S*UTILITY NORTHWEST*1*123456789**40!	Identifies the Utility as the receiver and their DUNS number.
N1*RS*XYZ SCHEDULER*1*567234987!	Identifies the Scheduler and their DUNS number.
N1*SJ*ABC SERVICE SUPPLIER*1*872369702**41!	Identifies the ESS as the sender and their DUNS number.
LIN*01*SH*EL*SH*CE*SH*HU!	This transaction is a request for a customer enrollment for electric service and for their historical usage.
ASI*7*021!	Identifies this as a request for an addition.
REF*12*763662108!	Specifies the Utility-assigned account number.
REF*RF*TC!	Identifies the regulatory and frequency provider.
REF*SP*TC!	Identifies the spinning operating reserve provider.
REF*SU*TC!	Identifies the supplemental operating reserve provider.
REF*TC*8R!	Identifies the transmission customer.
REF*BLT*ESP!	Specifies the billing option the Customer has chosen.
DTM*007*20011001!	Specifies the requested effective date.
NM1*MQ*2*JOE CORPORATION*****91*17324687!	Identifies the Customer and the Point of Delivery ID.
N3*1000 JOE CORP WAY!	Customer Address.
N4*MEDFORD*OR*76542!	Customer Address.
REF*MG*ABB123456!	Meter ID.
SE*19*000000001!	Ending transaction segment identifying the number of segments and the transaction

	number.

Drop Request
814-3
Inbound / Outbound

ST*814*000000005!	Beginning transaction segment identifying the transaction and sequence number.
BGN*13*UNW0004*20010331!	Request, sequence #0004 from UNW created on 3/31.
N1*8S*UTILITY NORTHWEST*1*123456789**41!	Identifies the Utility as the sender and their DUNS number.
N1*SJ*ABC SERVICE SUPPLIER*1*872369702**40!	Identifies the ESS as the receiver and their DUNS number.
LIN*01*SH*EL!	This transaction is a request to drop a customer for electric service.
ASI*7*024!	Identifies this as a request to drop a customer.
REF*12*763662108!	Specifies the Utility-assigned account number.
DTM*007*20010430!	Specifies the requested effective date.
NM1*MQ*2*JOE CORPORATION*****91*17324687!	Identifies the Customer and the Point of Delivery ID.
REF*MG*ABB123456!	Meter ID.
SE*11*000000006!	Ending transaction segment identifying the number of segments and the transaction number.

PACIFIC POWER

825 NE Multnomah
Portland, Oregon 97232

Each year our customers in Oregon have the opportunity to switch from regulated cost-based electric service (Basic Service) to a market-based pricing option offered either by Pacific Power or by an alternative Electricity Service Supplier (ESS). This option, known as Direct Access, was established by Oregon's electricity restructuring law that went into effect in 2002.

Choosing a market-based option is not mandatory. If no action is taken, you'll remain on the service you now have. Your current rate schedule is listed on the enrollment form below.

The enclosed brochure provides an overview of your options and explains the enrollment process. However, due to rules and regulations associated with Direct Access, we cannot provide advice to customers regarding their selection.

There is a limited time period in which to choose a market-based option. Annual enrollment begins at 12 p.m. (noon) on November 17, 2014 and ends at noon on November 24, 2014 for service beginning January 1, 2015 for a term of 12 months.

If you choose to switch from Basic Service to a market-based option, please fill out the form below and fax it to 1-800-835-0836. You may also fill out the form on our website. Because of tracking and auditing requirements, we cannot accept telephone enrollments.

For more information, please visit **pacificpower.net/directaccess** or call our Direct Access team toll free at **1-800-769-3717**, Monday through Friday, 8 a.m. to 5 p.m. We appreciate your business and look forward to continuing to serve you.

Sincerely,

Blaine Andreasen

Blaine Andreasen
Vice President Customer Services

Three ways to send us this information:
Fax: 1-800-835-0836
Mail: Pacific Power, P.O. Box 400, Portland, OR 97207
Web: pacificpower.net/directaccess

PACIFIC POWER

825 NE Multnomah
Portland, Oregon 97232

Change of Service Election Declaration (CSED)

☐ **Yes,** I choose to decline regulated cost-based service (Basic Service) currently provided by Pacific Power. As of January 1, 2015, I understand that my account will be placed on Daily Market Flux until a DASR/ESS Selection Form is received from a qualifying ESS and processed. *Enrollment deadline: To be valid, this form must be received by Pacific Power by noon on Friday, November 24, 2014.*

Company name:

Name of responsible party:

Service address, City, State, Zip:

Daytime phone: Meter #:

X ______________________________ Current Pacific Power rate schedule:
Signature

By doing this, I will have the flexibility to choose an alternative Electricity Service Supplier (ESS). I realize there are consequences if I would like to return to the Basic Service rate. Consumers who do not remain with the company's Basic Service do so at their own risk. Electricity is a commodity that is highly risky and can lead to large financial losses if it is not properly managed. The information contained herein should not be relied upon in any manner in choosing among the electricity supply options available to each consumer. Each consumer is responsible for retaining any and all commodity, risk management, legal and other professionals when seeking advice. Upon leaving Basic Service you are not eligible to return to Pacific Power's Basic Service, without penalty of a returning to service payment, until the next annual enrollment period effective January 1, 2016. Credit criteria apply. Options available to Oregon non-residential customers on rate schedules 23, 28, 30, 41, 47, 48, 51, 52, 53, 54 and 76R. Three-year option is available to non-residential customers on rate schedules 30, 47, 48, 730, 747 and 748.

DA15R

PACIFIC POWER

825 NE Multnomah
Portland, Oregon 97232

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Choosing a market-based option is not mandatory. If no action is taken, you'll remain on the service you now have. Your current rate schedule is listed on the enrollment form below.

The enclosed brochure provides an overview of your options and explains the enrollment process. However, due to rules and regulations associated with Direct Access, we cannot provide advice to customers regarding their selection.

There is a limited time period in which to choose a market-based option. Annual enrollment begins at 12 p.m. (noon) on November 17, 2014 and ends at noon on November 24, 2014 for service beginning January 1, 2015 for a term of 12 months.

Three-year ESS option eligibility: A three-year ESS option with a fixed transition adjustment is available for customers on rate schedules 47, 48, 747 or 748, or customers on rate schedules 30 or 730 under a single corporate name with at least 2 megawatts billing demand in the last 13 months. Enrollment for the three-year option begins at noon on November 17, 2014 and ends at noon on December 8, 2014.

If you choose to switch from Basic Service to a market-based option, please fill out the form below and fax it to 1-800-835-0836. You may also fill out the form on our website. Because of tracking and auditing requirements, we cannot accept telephone enrollments.

For more information, please visit **pacificpower.net/directaccess** or call our Direct Access team toll free at **1-800-769-3717**, Monday through Friday, 8 a.m. to 5 p.m. We appreciate your business and look forward to continuing to serve you.

Sincerely,

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Three ways to send us this information:

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Change of Service Election Declaration (CSED)

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☐ One-year option ☐ Three-year option
Pending verification of minimum eligibility requirements (if unchecked, you will be on the one-year option)

Company name:

Name of responsible party:

Service address, City, State, Zip:

Daytime phone: Meter #:

X ______________________ Current Pacific Power rate schedule:
Signature

By doing this, I will have the flexibility to choose an alternative Electricity Service Supplier (ESS). I realize there are consequences if I would like to return to the Basic Service rate. Customers who do not remain with the company's Basic Service do so at their own risk. Electricity is a commodity that is highly risky and can lead to large financial losses if it is not properly managed. The information contained herein should not be relied upon in any manner in choosing among the electricity supply options available to each consumer. Each consumer is responsible for retaining any and all commodity, risk management, legal and other professionals when seeking advice. Upon leaving Basic Service you are not eligible to return to Pacific Power's Basic Service, without penalty of a returning to service payment, until the next annual enrollment period effective January 1, 2016 for the one-year option or January 1, 2019 for the three-year option. Credit criteria apply. Options available to Oregon non-residential customers on rate schedules 23, 28, 30, 41, 47, 48, 51, 52, 53, 54 and 76R. Three-year option is available to non-residential customers on rate schedules 30, 47, 48, 730, 747 and 748.