ORDER NO. 15 405

ENTERED DEC 15 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1690

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Voluntary Renewable Energy Tariffs for Non-Residential Customers.	ORDER

DISPOSITION: PHASE II DETERMINATION DEFERRED;
UTILITIES ENCOURAGED TO FILE DRAFT VRET

This order memorializes the decision, made by a 2-1 vote at our December 14, 2015 Public Meeting, to defer a determination on Phase II of this matter.[1] To help inform our decision on whether it is in the public interest to allow utilities to offer voluntary renewable energy tariffs (VRETs) to nonresidential customers, we encourage PacifiCorp, dba Pacific Power, and Portland General Electric Company to file draft VRETs or a detailed design of proposed VRETs by April 14, 2016. To ensure reasonable outcomes that are in the public interest, the draft VRETs should be designed using the following guidelines:

1. Renewable Portfolio Standard (RPS) definitions for resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.

2. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.

3. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.

4. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.

5. VRET product design should be sufficiently differentiated from existing direct access programs.

[1] The Staff Report describing the Phase II proceeding is attached as Appendix A.

6. VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must proposed changes to their respective direct access programs to match those changes.

7. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.

8. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.

9. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Dated this 15 day of December, 2015, at Salem, Oregon.

John Savage
Commissioner

Stephen M. Bloom
Commissioner

Chair Ackerman, Dissenting:

Rather than defer consideration of Phase II, I would have concluded at this time that it is not in the public interest to allow utilities to offer VRETs and would have closed this docket.

Susan K. Ackerman
Chair

ORDER NO. 15 405

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 14, 2015

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

DATE: November 20, 2015

TO: Public Utility Commission

FROM: Elaine Prause and Michael Breish

THROUGH: Jason Eisdorfer and Aster Adams

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF: (Docket No. UM 1690) Voluntary Renewable Energy Tariffs for Nonresidential Customers. Docket opened by HB 4126.

STAFF RECOMMENDATION:

Accept Staff's recommendation to allow electric companies to offer voluntary renewable energy tariffs (VRETs) to nonresidential customers with the following conditions:

(1) Renewable Portfolio Standard (RPS) definitions which must apply to VRET products are for resource type, location, and bundled Renewable Energy Certificates (RECs).

(2) VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired on behalf of participants.

(3) The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.

(4) The VRET program size is limited to 300 aMW for Portland General Electric and 175 aMW for PacifiCorp.

(5) VRET product design should be unique to any existing programs (e.g. only long term contracts, less than 100 percent load eligible).

(6) The regulated utility should not be permitted to own a VRET resource.

(7) The regulated utility must demonstrate that there is no risk or cost shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system.

(8) Competitive bidding should only be required by the Commission if there is a proposed VRET design to serve aggregated VRET demand.

(9) The utility should be required to provide a clear power mix disclosure to VRET customers that explains the amount of power that the VRET customer is receiving from a VRET resource and utility-system resources.

In addition, close Phase 2 and open Phase 3 by authorizing electric companies to file schedules with the Commission for consideration of approval of rates, terms, and conditions of services offered under the VRET, subject to conditions adopted in Phase 2.

DISCUSSION:

Applicable Law

House Bill (HB) 4126 directed the Public Utility Commission (PUC or Commission) to conduct a study to consider the impact of allowing electric companies to offer Voluntary Renewable Energy Tariffs (VRETs) to their nonresidential customers.[1]

HB 4126 directs the Commission to consider the results of the Phase 1 study in conjunction with five statutory factors to determine a response to the threshold question: *whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers.*[2] The five statutory factors found in Section (3)(a-e) of the House Bill are:

Statutory Factor (1) Whether allowing electric companies to provide VRETs to nonresidential customers promotes the further development of significant renewable energy resources;

Statutory Factor (2) The effect of allowing electric companies to offer VRETs on the development of a competitive retail market;

[1] *See* Appendix 1 of the VRET Study for HB 4126.
http://edocs.puc.state.or.us/efdocs/HAU/um1690hau84412.pdf
[2] Oregon House Bill 4126, 3,(3), February 11, 2014.

Statutory Factor (3) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a VRET;

Statutory Factor (4) Whether the VRETs provided by electric companies to nonresidential customers rely on electricity supplied through a competitive procurement process; and

Statutory Factor (5) Any other reasonable consideration related to allowing electric companies to offer VRETs to their nonresidential customers.

If the Commission determines that it is reasonable and in the public interest to allow electric companies to provide VRETs, under Section (4) of HB 4126, electric companies can then file VRET proposals as tariffs processed in accordance with ORS 757.205, 757.210, 757.212, and 757.215.

Background

Staff conducted the VRET study through several workshops which were strongly shaped by both stakeholder comments and reply comments and produced study guidelines, an agreed upon issues list, and stakeholder-submitted models to forecast and consider potential impacts of VRETs. That study was accepted by the Commission in Order No. 15-258 in Phase 1 of Docket No. UM 1690.

In addition, with Order No. 15-258 the Commission closed Phase 1 and opened Phase 2, directing PUC Staff to file a report by October 15, 2015, that addressed the threshold question in the statute: "whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers."[3]

This Staff report provides 1) a review of the phased approach and the threshold question that Staff was asked to answer within this filing, 2) the statutory factors considered throughout the study process and Staff's analysis of these factors, and finally, 3) Staff's recommendation.

Phased Approach of UM 1690

- Phase 1. HB 4126 directed the PUC to conduct a study to consider the impact of allowing electric companies to offer VRETs to their nonresidential customers. Staff presented the results of that study at a Public Meeting on August 25, 2015.

[3] Staff's revised motion to amend the schedule to file the Staff report on November 20, 2015, was granted October 14, 2015.

At this Public Meeting, the Commission closed Phase 1 and directed staff to file a Staff Recommendation to kick-off Phase 2. The Staff filing must address the threshold question in the statute: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers.

- Phase 2. The Commission must consider the results of the VRET study in conjunction with the five statutory factors to determine whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers. This determination is considered the "threshold question" for this multiphase docket. In Phase 2, the Commission has the option to decide that VRETs are not reasonable and not in the public interest, which would result in not allowing the electric companies to offer VRETs and close this docket. The Commission also has the option of finding that VRETs are reasonable and in the public interest, potentially with the adoption of certain conditions, which could lead to Phase 3 of this Docket.

- Phase 3. If the Commission determines in Phase 2 to allow electric companies to offer VRETs to nonresidential customers, then, in Phase 3, the Commission may authorize an electric company to file a schedule with the Commission to establish rates, terms, and conditions of services offered under the VRET, subject to any conditions adopted in Phase 2. HB 4126 requires all costs and benefits associated with a VRET to be borne by the nonresidential customer receiving service under the VRET. In determining whether to approve a VRET schedule in Phase 3, the Commission must consider the same five statutory factors (listed below).

Analysis

Potential Benefits and Costs of a VRET

Even though there are two subparts of the threshold question, there is essentially one question asking whether the public interest benefits of offering a VRET outweigh the costs of implementing necessary conditions to that VRET. Before analyzing the threshold question and statutory factors, Staff found it necessary to list the potential benefits of utility offered VRETs from the perspectives of customers, utilities, nonparticipants, and the PUC. In doing so, the reasons why stakeholders are interested

in pursuing a VRET and the objectives that a successful design of a VRET should meet become clearer.

During the Phase 1 Study, there was not a clear, agreed-upon definition of a VRET, nor did HB 4126 provide a definition or list of attributes of a VRET. During Phase 1, Staff understood that many stakeholders describe a VRET as a utility offering that allows nonresidential customers to voluntarily elect to pay a different rate than their typical customer tariff because they are seeking renewable energy supply, an ability to make a "green power claim," and/or long-term and less-volatile energy costs.

Benefits
Summarizing from comments received by stakeholders during the Phase 1 study, benefits can be generally categorized as follows.

1) Provides additional choice to nonresidential customers.
    - The VRET meets a need no other existing option is fully able to address for them. This need could include, for example, purchasing renewable energy from a specific resource, not just unbundled RECs.
    - Offers the ability to lock in long term energy prices for price stability purpose.
    - Customers not interested in direct access may want to stay with their utility for this service.
    - Utilities may see benefit in being able to offer additional choice to their customers.
2) Leads to additional renewable resource development, beyond already planned investments, which in turn leads to additional societal benefits of a lower emissions energy system and economic benefits.

Not listed above is the possible perceived customer benefit that a VRET could provide a lower cost option to specific renewable resource products than direct access because the customer load is not leaving the utility system and therefore, transition charges would not apply. It is important to clarify that this perception is not a viable option for a VRET design because any design would need to follow the statute and not allow any cost-shifting to nonparticipants. Cost-shifting is the only way a VRET could be a "better deal" than direct access.

The economic benefits to society listed in number two above would need further analysis than was possible in Phase 1. These benefits could include state and local economic development if resources are constructed within the state or relatively close to load compared to fossil resources and would be specific to the resource. Considered at a high level, there are economic benefits for all ratepayers with a low carbon energy

system over the long term due to reduced fossil fuel price risk and compliance risk, and health benefits, all difficult to quantify without further study.

Costs
Certain conditions related to the design and execution of the VRET would need to be in place to ensure the VRET is reasonable and in the public interest. These conditions would be guided by the five statutory factors. Additional costs to implementing these conditions need to be considered.

In addition, the creation of a new tariff inherently brings added cost, even if no cost-shift to nonparticipants results. PUC Staff and Commission time used in development of conditions, approval of tariffs and ongoing considerations in addition to stakeholder time (utilities, industry, nongovernmental organizations) in development and implementation are real costs, the magnitude of which initially may not appear to be high. However, time spent developing a product that may not be used or provides only small incremental value is lost opportunity for other high priority regulatory issues

Staff's recommendation regarding the threshold question comes down to whether the potential benefits outweigh the costs of the conditions applied to a VRET program.

Review of Statutory Factors

The following sections of this Staff Report analyze the five statutory factors leading to Staff's assessment of necessary conditions. The final section balances the benefits of offering a VRET against the costs of implementing the necessary conditions to produce Staff's recommendation.

(SF1) Whether allowing electric companies to provide VRETs to nonresidential customers promotes the further development of significant renewable energy resources.

Although the statute does not require that the VRET promote the further development of significant renewable energy resources, this statutory factor directs the PUC to consider how the VRET impacts development and then whether that impact is reasonable and in the public interest, which would influence the response to the threshold question. If not reasonable or not in the public interest, the PUC could define necessary conditions to the VRET design that would make it so.

Is significant development a critical factor?
Without a specific VRET design against which to test significance, Staff flipped the question around and first asked, is significant development a critical factor in determining if the VRET is reasonable and in the public interest?

Based on the information presented in Phase 1, potential corporate participants are clearly interested in claiming the output of specific renewable resources.[4] This desire for sole attribution of resource output can only be met if the resource is not already "claimed" for other purposes such as the state RPS. RPS resources are shared resources towards which all ratepayers contribute and thus sole attribution is not possible. The VRET customer desire for resource claims would lead to the development of more resource which would lead to ancillary societal benefits of renewable resource development.

Informed by this reasoning, Staff finds that positive promotion of significant renewable resource development is a critical factor toward the decision of whether or not a VRET should be offered. In other words the VRET would need to lead to additional resource development or would not be worth the effort. The next question Staff answered was, "Are there specific conditions to the VRET design that would ensure significant development?"

Defining additionality
The renewable energy policy status quo in Oregon includes four categories of resources that are currently required and offered by utilities; the utilities' RPS percentage requirements by 2015, 2020, and 2025, renewable Qualifying Facility (QF) development, the solar capacity standard, and the utilities' existing voluntary unbundled REC-based residential and small commercial voluntary renewable energy portfolio options. The Commission could define a baseline using these categories of renewable resources to demonstrate additionality to the status quo of utility requirements.

For VRET resources to be "additional" to these categories, 1) the resource should be accepted as "on par" or of similar merit to resource types that currently meet Oregon policy requirements, 2) the resource could not "count" towards these categories nor negatively impact planned development in these categories, and 3) there is a clear link of attribution between existence of the VRET and the development of the resource.

1) Creating consistency of terms between renewable energy policies in Oregon would be a helpful first step in determining what is *significant* and how much *further development* amounts to "further development of significant renewable

[4] "Corporate Renewable Energy Buyer's Principles", as compiled by World Resource Institute and WWF, referenced in the Phase 1 study.

energy resources."[5] Oregon's definition for renewable resource types to meet compliance for the RPS[6] would need to be applied to the definition for eligibility of a VRET resource. In addition, the location of the resource would need to align with the requirements of the RPS, such that it must be located within the Western Electricity Coordinating Council.

2) Once the resource meets RPS eligibility, it would be able to generate RPS compliant RECs. HB 2941(6) clearly states that RECs generated from a VRET resource "may not be used by the electric company to comply with the requirements of the RPS." To ensure that those RECs are not applied towards RPS compliance, nor sold as unbundled RECs in the market, a necessary condition of the VRET should be that bundled RECs generated by the project are retired on behalf of the customer.

   There was informal consensus among many stakeholders that a VRET that offered only unbundled RECs (as defined by RPS laws to be without the associated electricity included) could already be offered under existing programs and should not qualify as *further development of significant renewable energy resources.* All three investor owned utilities have tariffs that include riders that allow customers to purchase unbundled RECs through the utilities.[7]

3) Ideally, to clearly show additionality, only new resources, developed in response to the creation of a VRET, should be eligible to participate. Because a condition requiring only new resources may hinder the launch of a VRET, Staff recommends that resources with an operational date no earlier than 2015 be eligible.

Finally, the VRET should not compromise renewable resource development within the three identified project categories. Because participant load would continue to be served by the utility, the load would continue to be included in the calculation of utility RPS requirements. Ratepayer costs to comply with the RPS would continue to be collected from participants. (Discussed further in Statutory Factor 3).

[5] Oregon House Bill 4126, 3,(3),(a), February 11, 2014.
[6] ORS 469A.010
[7] (*See* PGE Schedule 54, PacifiCorp Schedule 272, and Idaho Power Schedule 62, which are summarized in Appendix 2).

Staff Recommended Conditions Related to Statutory Factor 1:

- **RPS definitions which must apply to VRET products are for resource type, location, and bundled RECs.**
- **VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired on behalf of participants.**
- **The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.**

(SF 2) The effect of allowing electric companies to offer VRETs on the development of a competitive retail market.

Similar to statutory factor 1, HB 4126 does not require the impact on this factor, development of competitive retail markets, to be either negative or positive, but just to be considered within the Commission's overall evaluation of whether to allow a VRET in Phase 2, and if so, what conditions should apply. The VRET program that would allow a utility to offer a large direct access-eligible customer an alternative renewable option must be considered in the context of clear and long-standing statutory and policy direction to the Commission to promote competitive market options for large customers.

The statute does provide additional direction on competitive retail markets. HB 4126 Section 3(5) specifically states that rules adopted under ORS 757.646 (1) and 757.659 (7) pursuant to ORS 757.646 (1), which require the Commission to develop policies to eliminate barriers to competitive retail markets, do not bar the Commission from approving a schedule for a VRET that is otherwise consistent with HB 4126 and its findings. The phrase "do not bar" is interpreted by Staff to mean the Commission may approve a VRET, so long as it is consistent with the criteria set forth in HB 4126(3), even if the VRET may have an impact, which could be positive or negative on the competitive market that ORS 757.646 is intended to promote. Staff further interprets the statement to mean that possible VRET designs do not necessarily need to mimic the Commission approved rules related to the competitive retail market through Direct Access if criteria can be met in other ways.

Consideration of this factor encompasses two separate issues: 1) the impact of a VRET design on the direct access market, and 2) utility ownership of VRET resources. The first considers impacts on the existing direct access program and the second considers how ownership of VRET resources could impact the competitive retail market for VRET resources. Of the range of VRET models considered, Staff identified utility ownership of VRET resources to have the most potential for impacts to competitive markets for VRET resource development.

Impact of VRETs on the Direct Access Market

A competitive retail electricity market permits alternative suppliers, other than the regulated utility, to supply electricity to end-use retail customers.[8] A competitive market for nonresidential customers in Oregon was created in 1999 with the passage of SB 1149, which led to the development of a series of requirements through direct access tariffs offered by PGE and PacifiCorp. An Energy Service Suppliers (ESS) could, and some currently do, offer renewable energy through its product offerings under the current structure in Oregon, governed by the existing direct access requirements. In fact, within the Phase 1 study, many stakeholders noted that there may not be any reason to create a VRET because Direct Access is currently able to supply direct renewable energy products, as long as participants are willing to engage in direct access program costs, rules, and requirements.

Staff acknowledges that some stakeholders hold the view that current direct access programs are not effective and are not eliminating barriers to the development of a competitive retail market structure. In 2014, ESS load was 8.6 percent (190aMW) of PGE retail energy sales and 1.4 percent (20 aMW) of PacifiCorp retail energy sales.[9] These percentages have been increasing since 2011 when ESS load was 5.1 percent for PGE and 0.7 percent for PacifiCorp. Staff did not fully analyze the effectiveness of the direct access programs but rather, considered any adjustment to direct access to be outside the scope of this docket. For this analysis, Staff assumes no changes to direct access for the near term.

Some Phase 1 stakeholders also thought that if the VRET were an easier and better deal for participants, that some customers currently considering direct access would instead choose the VRET, thus negatively impacting direct access. Some existing direct access customers could possibly first return to the utility cost of service rates and then subsequently choose VRETs, resulting in an erosion of the competitiveness of the current direct access market. These scenarios implicate both potential cost-shifting and

[8] There does not appear to be a universal definition of a competitive retail electricity market. *See* The Electric Energy Market Competition Task Force, Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy at 84, Note 245 (2006), *available at* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf ("The Task Force adopts the convention of designating states as permitting retail competition on the basis of whether a state allows alternative suppliers to enter and obtain multiple, geographically dispersed customers. An even broader potential definition of retail competition would take into account policies that allow individual retail customers to provide some or all of their own generation needs (i.e., to make rather than buy electricity). Onsite generation is common in some industries in some sections of the country. Small onsite generation projects – often referred to as "Distributed Generation" or "Distributed Resources" projects – are gaining popularity as well.")

[9] http://www.puc.state.or.us/docs/statbook2014WEB.pdf

the utility's role in providing a VRET, issues we address in more detail below. In any case, the risk of either situation occurring is speculative and highly dependent upon the final design of the VRET. However, such a result would most likely be considered an unreasonable impact on direct access and therefore this outcome of the VRET may not be in the public interest.

Minimizing Impact on Direct Access
Staff considered what conditions would be needed to limit the impact of this uncertainty. Direct access participation is limited to 300 aMW in PGE territory and 175 aMW in PacifiCorp. To minimize the risk of the VRET growing beyond manageable levels, a similar capping parameter is recommended. To start, applying the same caps at levels equal to or lower than the direct access caps is recommended.

Another way to minimize potential negative impacts to direct access would be to create a product that is clearly differentiated from direct access or any other currently available renewable product. This condition would create a product that would be more likely to attract customers not currently participating in other programs. VRET needs to be aligned enough with customer needs to drive incremental participation and not substantively shift participation from other opportunities. If VRET conditions lead to the exact same requirements as direct access programs, there would be little to no distinguishing factors of VRETs that would encourage participation beyond current uptake of direct access through ESSs. Without clear differentiation of products that address customer interests to encourage participation, Staff is concerned that efforts spent by all parties in the creation of the VRET would not be worthwhile. Therefore, the expectation that a VRET is a new product, differentiated from existing options, is reasonable and in the public interest

Such differentiating factors could include limiting the percentage of load covered with the VRET to less than 100 percent and/or only offering long term contracts such as 10 years or longer. Direct access is designed to have the ESS supply 100 percent of energy needs with one, three, and five year opt out terms and return conditions. A VRET that only covers 75 percent of load and is a long term fixed price contract could attract a very different customer who is interested in hedging energy costs over the long term yet would like to stay with the utility.

Impact of Utility Ownership of VRET Resources on Competitive Retail Markets

The endurance and strength of a competitive market are functions of the type and number of consumers and producers who participate in said market. Staff focuses on this consideration as it addresses utility ownership of VRET resources. Economists generally agree that two specific characteristics, *natural monopoly* and *high barriers to*

entry, impede "robust competitive markets."[10] For the sake of making Staff's position on this matter clear to both the Commission and stakeholders, Staff below delineates how PGE's and PacifiCorp's participation in a competitive market engendered by a VRET would align with these competitive market-precluding characteristics.

By means of ORS 758.400 through 758.475, PGE and PacifiCorp are granted authority to be the sole providers of electric service in the companies' respective allocated service territories. This recognizes the nature of the operations of PGE and PacifiCorp are inherently that of a *natural monopoly*, and these monopolies are regulated to maximize benefits to Oregon residents. An electric utility monopoly is afforded a number of advantages, some in part due to the unique economic environment in which they operate, including access to cheaper capital, captive customers, market and customer data, name recognition, and purchasing power. A monopoly's participation in a VRET market would reduce and possibly eliminate the competitive nature of such a market due to these aforementioned advantages being unavailable to potential producers.

High barriers to entry have traditionally been defined as "any costs that must be borne by firms seeking to enter (or exit) an industry that are not borne by incumbent firms."[11] In a VRET market, such a cost could include the large initial capital expenditure for generation and transmission assets. A utility would be able to absorb the failure of a generation asset (a failed market entry) through means afforded to it by way of its regulated status and recognition of its public benefit, whereas a third party or customer would not necessarily have such loss-mitigating means available to them. Barriers like this introduce additional risk to participants interested in participating in a market where utilities are permitted to operate; this particular risk is detrimental to the competitive aspects of a market.

In addition to natural monopoly advantages and barriers to entry, utility participation in a VRET market may further inhibit competitiveness due to a utility's *horizontal market power. Horizontal market power* is characterized by "a firm's ability to influence price in a single market," which can be conducted through *cross-subsidization.*[12] A utility can utilize resources that are strictly designated for its cost-of-service obligation to meet the needs of its VRET customers; these resources include, but are not limited to, staffing, information systems, and means of meeting Oregon regulatory and legal requirements. A regulated utility's ability to exercise either *horizontal market power* while participating in a market despite regulatory oversight will diminish the viability and strength of the competitive nature of that market.

---

[10] Lesser, Ph.D and Giacchino, Ph.D, *Fundamentals of Energy Regulation, 2nd Edition.* Reston: Public Utilities Reports, Inc., 2013.
[11] Ibid., 28.
[12] Ibid., 314.

Staff notes a claim made by utilities in this docket and UM 1746 that utility ownership and subsequent participation in a competitive market enhances the market by offering an additional option to customers that often is a lower price. This particular view of market participation is deficient in dimensions of both temporality and benefit directionality. In the short term, customers may benefit from a lower price offered by a monopoly. Other participants may either be unable to enter the market or forced out due to the inability to compete with a price that is enhanced by monopolistic advantages. In the long term, such a scenario ultimately produces harm to the market in the form of fewer participants, riskier signals to investors, and subsequent higher prices. A competitive market is characterized by the actions of buyers *and* sellers. A utility's claim of benefits flowing to customers due to lower prices fails to take into account the needs of ensuring a fair market for sellers as well.

Additional Conditions Triggered by Utility Ownership
In Staff's assessment, utility ownership of VRET resources would not add clear benefit but would add cost of managing to meet additional conditions.

A utility VRET offering that has more flexible terms than direct access could amount to an unreasonable advantage for the utility. Therefore, first, there would have to be an additional condition to make VRET terms (timing and frequency of VRET offerings) the same as direct access terms.

Second, utilities would not be allowed to rate base these resources and the costs of the individual resources would have to be tracked separately. In this case, there could be multiple VRET resources owned by the utility each being tracked carefully to avoid potential cost-shifting. Demonstration of no cost-shifting, although not unique to utility owned VRET models, would be more complex in this situation as the PUC would need to verify all project costs are incurred only by shareholders and participants.

The third additional condition would be that the PUC would need to approve all VRET contracts to ensure that regulated utilities were providing service to their retail loads at just and reasonable rates. This condition would include requirements that all VRET project details would need to be provided to the PUC and reviewed relative to the proposed tariff rate. Each resource and therefore possibly each tariff rate would need this detailed review of justification for just and reasonable rates by the Commission. Demonstration of participant commitment to the project, including all contracts between the utility and the participant, and explanation for how project costs are covered by participants in the event that the project is undersubscribed would be required for the Commission to be able to review the proposed tariff.

In summary, these three additional conditions show that a utility-owned VRET may not create much additional value and creates additional regulatory costs and burdens.

- All VRET product terms and conditions would be the same as direct access.
- The regulated utility cannot rate base VRET resources and all costs must be tracked separately.
- All project details including costs, proposed rates, contracts between utilities and customers, and demonstration that all costs and risks are borne by participants and shareholders must be provided.

Due to the reasons described above, Staff recommends not permitting the regulated utility to own a VRET resource.

Staff Recommended Conditions Related to Statutory Factor 2:

- **The VRET program size is limited to 300aMW for Portland General Electric and 175 aMW for PacifiCorp.**
- **VRET product design should be unique to any existing programs[13] (e.g. only long contract terms, less than 100 percent load eligible)**
- **The regulated utility should not be permitted to own a VRET resource.**

(SF 3) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a VRET.

The importance of this statutory factor to consider direct and indirect impacts on nonparticipating customers is further reinforced by language in Section 3(4) of HB 4126[14] which strictly prohibits cost-shifting to nonparticipating customers. Therefore, any acceptable VRET design would need to demonstrate that all associated costs are borne only by participating customers.

Cost Categories
Direct and indirect costs of a VRET can generally be summarized into four categories;

1. Direct cost of the energy supplied plus any services needed to integrate the energy into the utility system and meet customer demand,

[13] This condition assumes no utility ownership.
[14] HB 4126 (2014), Section 3(4) (stating, in part: ". . . All costs and benefits associated with a voluntary renewable energy tariff shall be borne by the nonresidential customer receiving service under the voluntary renewable energy tariff.").

2. Cost to administer and promote the tariff, billing, educating, and fielding customer calls regarding VRET products, all of which would likely utilize assets which are paid for by all utility customers (cross subsidization),

3. Costs incurred due to risks of resource performance, low uptake or customer abandonment from the VRET, and

4. Risks of costs currently paid for by eligible customers no longer being collected through the VRET, specifically, RPS compliance costs and system investments.

Since there is not an agreed upon VRET model against which to verify that each of these cost categories is properly addressed, Staff finds that the most comprehensive approach to addressing the need for no cost-shift of each category listed above is to require the following condition when the utility brings forward a VRET tariff for approval.

> **The regulated utility must demonstrate that there is no risk or cost-shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system.**

Regulated utility programs manage for no or minimal cost-shift today for voluntary renewable programs and direct access participants. Under a scenario where the regulated utility may own a VRET resource, there would clearly be costs for building a VRET resource that would need to be accounted for and separated from costs related to the cost of service rate based system. Affiliates of regulated utilities are often formed to create a separation between regulated activities and are often satisfactory solutions to the *cross-subsidization* issue described under statutory factor 2. In fact, the use of affiliates was contemplated in SB 1149 and the direct access regulations.[15] The regulated utilities, in general, have not expressed any interest in forming affiliates. In Docket No. UM 1746, Community Solar, Staff recommended against utility ownership due to negative impacts on competitive markets and also due to added complexities of adhering to minimizing cost-shifting of the resource investment to nonparticipants. In this case, the statute clearly states that no cost-shift is allowed, making the review and approval of the resource cost allocations utilities would need to manage, an obligation PUC staff would take on for the life of the resource.

Demonstration of No Cost-Shift

1. Direct costs of VRET energy and services can only be incurred by participants, project owners, or shareholders of the regulated utility, depending upon the

[15] *See* ORS 757.015 (Affiliated interest defined), *See* also OAR 860-086-0010 (2) ("Affiliate" means a corporation or person who has an affiliated interest, as defined in ORS 757.015, with a public utility).

VRET design chosen. Utilities would demonstrate no cost-shift by providing all project contracts for the VRET resources and services and clearly justify the rate charged to participants as tied to these project and service costs. Expected payment from participants must fully cover these costs.

2. Regardless of ownership of the VRET resource, costs in the second category, program administration, would mainly be incurred by the utility. Again, the regulated utilities have experience accounting for portions of these costs allocated to voluntary program administration and delivery and would need to demonstrate similar practices for VRETs. The utilities would need to document utility staff time spent on VRET work across all administrative functions of customer service, billing, marketing and how those costs translated to charges incurred by participants (or shareholders).

3. The third category, risk that VRET resources could be undersubscribed due to insufficient customer interest or become stranded resources if VRET customers return to the cost of service system, depends on how well the VRET is designed to meet customer needs. If VRET resources are under subscribed or become stranded, strict prohibitions on assigning those costs to nonparticipating customers would have to be demonstrated within the proposed design. Cost associated with VRET resource performance would be addressed in contractual arrangements between projects and the utility purchasing the output with costs borne by the participant or shareholders. Demonstration of no cost-shift would require sharing these contracts with the PUC the provisions regarding liability of performance risk and subscription risk clearly showing no impact to nonparticipants.

4. The fourth cost category, risk of system obligations currently shared by all customers no longer applying to VRET customers was discussed extensively within Phase 1. Because the VRET is conceived as a product offered through the utility as opposed to outside the utility like direct access, utility system obligations are still seen as applying to VRET participants. Stakeholders offered and reviewed many suggestions for rate design that could be used to ensure that participants are continuing to contribute to overall system investments. Because the specific tariff designs depend upon the final VRET parameters chosen, Staff recommends that the overall condition, to require the utility to demonstrate no risk or cost-shift, would sufficiently address this factor without the need to require prescriptive approaches, leaving some flexibility in VRET design.

   Demonstration of no cost-shift would include comparison cases of system cost allocations over the life of the VRET contract terms with and without the

existence of a VRET. Nonparticipant rates would remain the same in either case, only participants costs would change. Although future system costs for new investments would be unknown, the methodology utilities will employ to ensure nonparticipant future costs are not impacted would need to be clearly explained.

RPS Compliance Costs

RPS compliance costs, however, may require separate consideration. Under ORS 469A.052, RPS compliance requirements are calculated as a function of the utility's retail load, meaning no loads are exempt from inclusion in the RPS compliance obligation. Depending on how VRET loads are characterized, VRET customers could be part of the utility's total retail load which would not impact the magnitude of the RPS target, but those resources could not count towards compliance (see HB 4126 Section 3(6)).

If VRET load could be characterized more like third party served load through direct access, RPS compliance requirements could follow the methodology used by ESSs. RECs from VRET resources are prohibited from being used to comply with the RPS, therefore, RPS compliance requirements from VRET load could be fulfilled through purchases of unbundled RECs. This is similar to how ESSs comply with their RPS targets based on the service territory where their customer load is located. Although the renewable energy supplied to customers is separate from the utility cost of service load, the energy component will be delivered and billed by the utility. Staff reasons that VRET load will continue to be included within the utility RPS obligation calculation, leading to no compromise of the total RPS requirement, and that VRET participants will continue to contribute to covering the costs, without cost-shift to nonparticipants.

Efficient Design

Finally, the VRET design should be efficient for all parties involved, easy to participate in, easy to track and manage, and minimize time/resource cost to the utility, participant, resource owner, OPUC, and other stakeholders. This recommendation is more of a general observation for best practices in VRET design rather than a required condition.

Staff Recommended Conditions Related to Statutory Factor 3:

- **The regulated utility must demonstrate that there is no risk or cost-shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system.**

(SF4) Whether the VRETs provided by electric companies to nonresidential customers rely on electricity supplied through a competitive procurement process.

Of the many VRET designs proposed and discussed by stakeholders in Phase 1, outside of customer and utility owned options (discussed further in SF #5), two high level designs generally emerge related to VRET resource selection.

1. Bi-lateral negotiated agreements between customers and project developers for the renewable energy delivered to the utility and the utility charges the customer the negotiated rate.

2. Multiple, likely smaller customers load portions are aggregated by the utility and served by one or more projects where utility runs an RFP on behalf of customers.

In the first case, because the regulated utility should not be permitted to own a VRET resource (see Condition #4 resulting from Statutory Factors 2 and 5) it would not be necessary for the PUC to require competitive procurement. Potential VRET customers and ESSs or IPPs would likely negotiate costs and attributes of renewable resources. These nonresidential customers, which typically have large loads, may have preferences, expertise, or market connections that could ensure competitively priced VRET resources. Requiring the use of a competitive procurement process when it may not be needed to yield the lowest cost procurement could add unnecessary administrative costs that raise prices for potential VRET customers.
However, in the second case, since the utility would be negotiating with projects for energy prices on behalf of customers, it is reasonable and in the ratepayers' best interest to require resource selections to go through a competitive procurement process to help ensure the lowest cost procurement of VRET resources.

Staff Recommended Condition Related to Statutory Factor 4:

- **Competitive bidding should only be required by the Commission if there is a proposed VRET design to serve aggregated VRET demand.**

(SF5) Any other reasonable consideration related to allowing electric companies to offer VRETs to their nonresidential customers.

Many stakeholders highlighted additional potential VRET considerations in their comments: consumer protection, requiring participants to acquire all cost-effective

energy efficiency, state economic and business development goals, whether the complexity is worth the effort, changes to direct access, and long-term implications considering the CPP and the numerous other challenges to be faced by the Commission in coming years, among others.

The majority of these topics are addressed within the prior four statutory factor discussions (state economic and business development goals, changes to direct access) or within the overall assessment of the threshold question regarding the necessary conditions (whether the complexity is worth the effort). For this analysis, Staff chose to highlight consumer protection issues and raise a separate but overarching issue of VRET resource ownership and relationships which ties to the issue of long-term implications.

Consumer Protection

Staff agrees that issues related to consumer protection should be considered further within VRET design but are largely addressed under other existing rules and policies that would apply to the design of the VRET. Two key points surfaced in the consumer protection context: (1) need for third-party certification, and (2) power mix disclosures.

Third party certification

Stakeholders questioned whether a VRET could require products to have third-party verification or oversight that ensures that the products conform to customer "green claim" expectations and renewable energy and environmental attribute markets. For example, Green-e certification is used for the residential voluntary renewable energy program in Oregon. If RPS eligible resource criteria and RPS definitions related to renewable resources are also used for the VRET to fulfill the first statutory factor, ODOE could certify those resources as it does for RPS compliance.

Resources developed for a VRET, for which customers claim environmental attributes, should be fairly characterized in utility power mix disclosures. If environmental attributes associated with VRET renewable energy procurement are conveyed to customers (as recommended by Staff in Statutory Factor 1), then those attributes are not part of the utility's cost of service rate based system, cannot be claimed by the utility, and would not be reflected in the utility's power mix disclosures.

Power mix disclosure

The resource mix associated with the VRET could be included as a label pursuant to OAR 860-038-0300 (Electric Company and Electricity Service Suppliers Labeling Requirements). If specialized products under a VRET are negotiated for individual customers[16] then customers may need to be provided with specialized labels so that

[16] *See*, e.g. NIPPC's Direct Access VRET Model

VRET customers clearly understand the resources they are receiving compared to the utility's cost of service rate-based power mix. More specific disclosure questions may arise if products under a VRET permit customers to maintain a connection to the cost of service rate-based system[17] Because the resource mix of the VRET product is likely of great interest to the participant, this issue of disclosure seems to be fully addressed through the tariff approval and customer enrollment process and therefore Staff initially considered that it would not be necessary to develop a specific condition related to this issue for review of the threshold question. However, further research is needed to ensure that is the case. Therefore, a condition requiring that utilities provide a clear power mix disclosure to VRET customers that explains the amount power that the VRET customer is receiving from a VRET resource and utility-system resources is included.

VRET Resource Ownership and Relationships

In Phase 1, at least a dozen VRET models were developed by Staff and stakeholders for discussion. Resource ownership was a key element and one in which stakeholders did not reach a consensus.

Customer Ownership

In the benefits and costs discussion of this report, Staff noted that during Phase 1, many stakeholders described a VRET as a utility offering that allows nonresidential customers to voluntarily elect to pay a different rate than their typical customer tariff because they are seeking renewable energy supply, an ability to make a "green power claim," and/or long-term and less-volatile energy costs.

Reasons given to extend this definition to include customers as owners seemed intended to address other market barriers. For example, one stakeholder noted that the VRET could be a way to create a virtual net metering product where generation at one customer site could be delivered to another site via the VRET arrangement. In other words, customer owned VRET resource models seem to address other issues outside of the scope of what a VRET is intended to provide.

Net metering, QFs, direct PPA sales to third parties, and partial requirements services are existing ways in which customers can own resources. Although there may be limitations to these pathways, attempting to address them through this process seems outside the scope and therefore may not be within the criteria of being reasonable and in the public interest. However, because customer ownership raises many additional questions for Staff that were not fully investigated in Phase 1, Staff is not recommending precluding customer ownership from potential VRET designs. Remaining questions include; how would the rate the utility would charge participants for the VRET resource

[17] *See*, e.g., PGE Third Party PPA Model

be determined? Could other VRET participants "subscribe" to the resource output? As utilities bring forth VRET tariffs for approval, these questions would be addressed prior to Commission approval.

Utility/Customer Relationship
Staff outlined key arguments related to the detrimental impact of utility ownership of VRET resources on the competitive retail market in the Statutory Factor 2 section. When considering potential cost-shifting in Statutory Factor 3, Staff cautioned against allowing utility resource ownership due to complexities of demonstrating no cost-shift and the strict prohibition on cost-shift in the statute. In this section, Staff considers the broader question of utility ownership of VRET resources related to the design and intent of the regulated utility model and the implications of utility ownership on the future of the utility industry.

Regulated utility resource investment planning typically begins within the integrated resource planning (IRP) process where utilities first assess the energy and capacity needs of their entire customer base for the next 20 years and then identify the most optimal mix of market purchases and future capital expenditures to meet those needs at least cost and lowest risk to all ratepayers. Regulated utilities justify their reasonable and prudent investments in new resource development to the PUC for approval in applying those costs to be recovered from all ratepayers and allowing the utility to earn a return on the investment. By linking the need for the resource to meeting the energy needs of their customers in the least cost, lowest risk manner, regulated utilities are displaying prudent planning on behalf of the customers they serve. Current electric utility IRPs have not identified the need for new centralized resource investments before 2020, and have not identified additional renewables be built beyond those needed for RPS compliance.

The idea of a VRET contemplates the premise that specific resources are built and used to meet specific customer preferences, a utility model that is not aligned with current IRP practices where the utility must plan for all customers. Individual consumer choice is not incorporated into IRP planning, rather, only optimization of the system for least cost, lowest risk is. As one stakeholder noted in Phase 1 "[p]roviding specialized products to particular customers begins to veer away from the core mission" of the regulated utility[18]. Furthermore, providing a specialized product for a particular set of customers already served by the utility's cost of service or eligible to be served contradicts the core mission of a regulated utility, which is to be the provider of accessible, equal and fair service.[19]

[18] Phase 1 study, Appendix 5, page 18
[19] The Commission's mission is to ensure fair and just rates are provided by utilities to its customers. Given the current regulated, cost-of-service product offered to all customers, "unjust or undue

Reconciling the VRET load and resources, regardless of resource ownership, with utility IRP processes should be clearly stated. VRET participants are still considered customers of the utility; therefore, their load remains within utility retail sales. Utilities would still need to include VRET load in IRP planning for capacity and integration planning at a minimum with the contract terms that describe plans to serve load incorporated as energy resources. Uncertainty as far as how much of load will be served through VRETs in the future will occur, but the recommended condition to cap the overall size of the VRET participation from Statutory Factor 2 will contain the magnitude of risk.

Providing customer choice was one recognized potential benefit of the VRET. Staff agrees that customer choice that leads to further renewable resource development is beneficial, but cautions that focusing on meeting the specific resource interests of a subset of customers could be detrimental to the regulated utility model and other options to meet customer choices which do not require utility ownership are available.

In summary, no additional conditions result from this section only the understanding that the relationship between the utility and the VRET customer is clear. The VRET customer load remains retail load of the regulated utility and as such, the utility is obligated to serve that load.

Staff Recommended Condition Related to Statutory Factor 5:

- **The utility should be required to provide a clear power mix disclosure to VRET customers that explains the amount of power that the VRET customer is receiving from a VRET resource and utility-system resources.**

---

discrimination among customers is forbidden. Under conditions of near monopoly, discrimination in price and perhaps service may become profitable to a business. Since there are few substitute services available, customers would be helpless in such a situation." Phillips, Jr, Charles F., *The Regulation of Public Utilities Theory and Practice,* Public Utilities Reports, Inc. (Arlington): 1993, at page 119.

Analysis of Threshold Question: Whether to allow a VRET?

The statute requires the Commission to decide the answer to the threshold question: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers. As used in Section 3(2) of HB 4126, Staff's counsel advises that the meaning of the phrase "is reasonable and in the public interest" is informed by the five statutory factors set forth in Section 3(2)(a)-(e).[20]

Upon review of the five statutory factors, Staff identified certain conditions which, individually, would lead to reasonable outcomes that are in the public interest. The conditions ensure that; 1) the VRET resources would be additional to current renewable resource development, 2) VRETs minimize any negative impact on the competitive retail market, and that 3) no cost-shifting to nonparticipants results.

The final step of the analysis is to determine whether the conditions, in combination, lead to benefits that exceed the costs.

The benefits center on providing greater customer choice and increasing renewable resources in the energy system. Phase 1 proceedings were highly attended by a committed group of stakeholders working to provide their input on how best to implement a VRET to provide greater customer choice. Stakeholders see a segment of customers for which a VRET would be of interest. If there are unnecessary regulatory barriers hindering the development of a new energy product that is reasonable and in the public interest, Staff sees benefit to working with stakeholders to explore new options.

The necessary conditions of the VRET are intended to result in a product that meets customer needs such that they would want to participate and their subsequent participation is not at the expense of nonparticipants. If VRET designs meet participant needs, additional renewable resources will be built leading to customer specific and societal benefits of a lower emissions energy system.

---

[20] Generally, Commission orders interpreting the meaning of "in the public interest" are specific to the statute at issue in that proceeding. For example, in the context of utility mergers, "public interest" under ORS 759.375 means there is "no harm" to the public if the merger is allowed. *See* Order No. 09-169. But, in the context of an entity acquiring a utility, "public interest" under ORS 757.511 means there must be "net benefits" to the public if the acquisition is allowed. *See* Order No. 06-082. In the context of ORS 757.415(2)(b) (purposes for which securities and notes may be issued), the Oregon DOJ has opined that "compatible with the public interest" is explained by the context of the other language/factors/criteria set forth in that particular statutory section.

Staff finds that the benefits do narrowly outweigh the costs, enough to warrant that the Commission should allow the utilities to provide VRETs under the stated conditions. Simply put, it seems worth the effort to be receptive to VRET proposals. Utility, customer, and developer response to the VRET conditions will ultimately determine if and when specific VRETs are brought forward to the Commission for review and approval. Until proposals come forward, simply allowing utilities the ability to design tariffs without cost-shift to nonparticipants is reasonable and in the public interest.

Conclusion

The Commission should allow regulated utilities to offer VRETs to nonresidential customers with the following conditions:

(1) RPS definitions which must apply to VRET products are for resource type, location, and bundled RECs. ***(SF 1)***

(2) VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired on behalf of participants. ***(SF 1)***

(3) The year in which a VRET eligible renewable resource became operational should be no earlier than 2015. ***(SF 1)***

(4) The VRET program size is limited to 300aMW for Portland General Electric and 175 aMW for PacifiCorp. ***(SF 2)***

(5) VRET product design should be unique to any existing programs (e.g. only long term contracts, less than 100 percent load eligible). ***(SF 2)***

(6) The regulated utility should not be permitted to own a VRET resource. ***(SF 2)***

(7) The regulated utility must demonstrate that there is no risk or cost-shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system. ***(SF 3)***

(8) Competitive bidding should only be required by the Commission if there is a proposed VRET design to serve aggregated VRET demand. ***(SF 4)***

(9) The utility should be required to provide a clear power mix disclosure to VRET customers that explains the amount of power that the VRET customer is receiving from a VRET resource and utility-system resources. ***(SF 5)***

In addition, close Phase 2 and open Phase 3 by authorizing electric companies to file schedules with the Commission for consideration of approval of rates, terms, and conditions of services offered under the VRET, subject to conditions adopted in Phase 2.

PROPOSED COMMISSION MOTION:

The Commission accept Staff's recommendation to allow the regulated utility to offer voluntary renewable energy tariffs to nonresidential customers with Staff's recommended conditions.