BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

AR 622

In the Matter of Rulemaking for Community-Based Renewable Energy Projects.	JOINT COMMENTS OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION AND THE RENEWABLE ENERGY COALITION

INTRODUCTION

The Community Renewable Energy Association ("CREA") and the Renewable Energy Coalition ("REC") submit these Joint Comments on the Public Utility Commission of Oregon's ("OPUC" or "Commission") proposed rule.

CREA and REC appreciate the opportunity to comment on the Commission's proposed rule for small-scale community-based renewable energy generation facilities, as required by ORS 469A.210. This rulemaking is central to the mission of both CREA and REC because both organizations have the mission of advocating for policies that will lead to successful development and operation of small-scale community-based renewable energy generation facilities in Oregon. The Oregon legislature has also unambiguously expressed support for such policies. As early as 1983, the legislature enacted provisions regarding Oregon's implementation of the Public Utility Regulatory Policy Act of 1978 ("PURPA"), ORS 758.505 *et seq*, which states "[i]t is the goal of Oregon to . . . [p]romote the development of a diverse array of permanently sustainable energy resources using the public and private sectors to the highest degree possible . . . ." ORS 758.515(2)(a). In the legislation at issue in this rulemaking, the legislature unambiguously proclaimed that "community-based renewable energy projects . . . *are an essential element of this state's energy future*." ORS 469A.210(1) (emphasis added). The

Commission is the state agency that the legislature has charged with implementing this important eight-percent requirement and related policies.

In light of the fact that these small-scale facilities are "an essential element of this state's energy future," *id.*, any ambiguities in the statute should be interpreted in a manner that will in fact lead to further development of such facilities *in the future*. The statute should not be creatively interpreted in a manner that paradoxically leads to a conclusion that no further development of such facilities is necessary. As expressed in the informal phase of this rulemaking and at the public hearing, CREA and REC urge the Commission to adopt rules that will actually lead to further development of small-scale community-based renewable facilities. Despite clear legislative intent, some parties have made proposals in this rulemaking that would seriously undermine the legislature's intent that small-scale community-based renewable energy facilities will be an essential element of the state's energy future.

CREA and REC provided detailed comments on all major issues related to the rulemaking during the informal process, filed on September 28, 2018, and November 28, 2018. In these comments, we reiterate and elaborate upon the points previously made.

COMMENTS

The purpose of this rulemaking is to implement and ensure compliance with the Oregon legislature's directive that is intended to promote small-scale community-based renewable generation facilities of 20 megawatts ("MW") of generating capacity or less and certain biomass cogeneration. This requirement was formerly identified in the original version of Oregon's renewable portfolio standard ("RPS") as a "goal" that administrative agencies of the executive branch were charged with achieving. *See* 2007 Or Laws ch 301, § 24.[1] CREA was the lead sponsor of this provision, and it would not have passed but for CREA's participation in the legislative process.

The 2007 statutory requirement specifically provided that "[a]ll agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section." *Id.* However, it became apparent to CREA and REC that the state agencies most responsible for achieving this goal were not even monitoring compliance status, let alone establishing policies and procedures promoting the goal.

Thus, CREA and REC engaged at the legislature in 2016, to, among other modifications, convert the eight-percent goal to an affirmative requirement no less significant than the RPS's other compliance requirements. *See* 2016 Oregon Laws, ch 28, § 14. In 2017, a further amendment clarified that the facilities meeting the eight-percent requirement must be small-scale community-based facilities that also qualify under the general RPS criteria in ORS 469A.025. *See* 2017 Oregon Laws, ch 452, § 1.

The critical statutory language in the current version of ORS 469A.210 provides:

> (1) The Legislative Assembly finds that community-based renewable energy projects, including but not limited to marine renewable energy resources that are either developed in accordance with the Territorial Sea Plan adopted pursuant to

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1 This provision provided:

> Goal for community-based renewable energy projects. The Legislative Assembly finds that community-based renewable energy projects are an essential element of Oregon's energy future, and declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section.

Id.

> ORS 196.471 or located on structures adjacent to the coastal shorelands, are an essential element of this state's energy future.
>
> (2) For purposes related to the findings in subsection (1) of this section, by the year 2025, at least eight percent of the aggregate electrical capacity of all electric companies that make sales of electricity to 25,000 or more retail electricity consumers in this state must be composed of electricity generated by one or both of the following sources:
>
> > (a) Small-scale renewable energy projects with a generating capacity of 20 megawatts or less that generate electricity utilizing a type of energy described in ORS 469A.025; or
> >
> > (b) Facilities that generate electricity using biomass that also generate thermal energy for a secondary purpose.
>
> (3) Regardless of the facility's nameplate capacity, any single facility described in subsection (2)(b) of this section may be used to comply with the requirement specified in subsection (2) of this section for up to 20 megawatts of capacity.

This legislative history could not be more clear. In multiple sessions over the course of a decade, the legislature has expressed support for small-scale community-based resources to be part of Oregon's energy mix. With these rules, the Commission must make a fundamental decision, to comply with the clear direction of the legislature, or to be persuaded by utility arguments intended to minimize such development in this and other proceedings irrespective of the legislature's desires.

In the following sections, these comments will specifically address each of the proposed rules.

Proposed OAR 860-091-0000

> ***Applicability***
>
> *(1) These rules are intended to implement ORS 469A.210.*
>
> *(2) The rules contained in this division apply only to an electric company that makes sales of electricity to 25,000 or more retail electricity customers in this state.*

(3) Upon request or its own motion, the Commission may waive any of the Division 091 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

CREA-REC Comments:

CREA and REC have no specific comments on this aspect of the proposed rule.

Proposed OAR 860-091-0010

Definitions

For purposes of OAR 860-091-0000 through 860-091-0070:

(1) "Electric company" has the meaning in ORS 757.600.

(2) "Nameplate capacity" means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Nameplate capacity is usually indicated on a nameplate attached to the individual machine or device.

(3) "Renewable attributes" means the environmental attributes associated with energy generation represented by a renewable energy certificate that can be used to comply with Oregon's renewable portfolio standards in ORS 469A.050 and ORS 469A.055. Renewable attributes do not include greenhouse gas offsets from methane capture not associated with generation of electricity and do not include environmental attributes represented by a thermal renewable energy certificate created under ORS 469A.132.

CREA-REC Comments:

The definitions contained in this section are a good start, however the list of definitions is incomplete. The list should also include other critical terms in the statute and the rules.

The Commission should also include definitions of "electrical capacity," "aggregate electrical capacity," and "generating capacity," which are the critical terms used by the legislature. As discussed further below, CREA and REC maintain the following definitions would be consistent with the statute's use of these terms:

> "Electrical capacity" means a generation facility's ability to contribute capacity to the electric company. For purposes of this rule, an individual generation facility's electrical capacity will be measured according to its resource type and the electric company to which it delivers its energy and capacity in accordance with the percentages of nameplate capacity provided below:
>
> [Insert table of contribution to peak percentage for each resource type from PacifiCorp and Portland General Electric Integrated Resource Plans][2]
>
> "Aggregate electrical capacity" means the sum of the electrical capacity of multiple generators.
>
> "Generating capacity" means nameplate capacity.

The rule should also clarify the meaning of the facilities described in ORS 469A.210(2)(b) – facilities that "[g]enerate electricity using biomass and generate thermal energy for a secondary purpose." These statutory terms also appear in ORS 469A.132, which requires creation of "thermal renewable energy certificates" from such facilities. The Oregon Department of Energy ("ODOE") recently completed a rulemaking defining the critical statutory terms, and it would therefore make sense to use the same definitions in this context. *See* OAR 330-160-0015(21) (defining "secondary purpose"); OAR 330-160-0080 (describing criteria for a facility to be a facility that generates thermal energy from generation of electricity using biomass).

CREA and REC note that the proposed rule has removed a definition of "Environmental Attributes" circulated during the informal process. CREA and REC agree with the proposed rule's use of the term "Renewable Attributes." The revision ensures consistency between the

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2 These figures are readily available in the utilities' IRPs. PacifiCorp's 2017 Integrated Resource Plan, Volume 1, table 5.13, at page 88, provides the following values for the west balancing authority: wind 11.8%, fixed tilt solar PV 53.9%, single axis tracking solar 64.8%. PGE's 2016 IRP Update, Appendix D, Table 9, at page 105, provides following values 16.7% wind (first 100 MWs), 14.4% solar (first 100 MWs), and wind 12.8% (second 100 MWs), Solar 11.2% (second 100 MWs), etc.

attributes required for compliance with ORS 469A.210 and the attributes conveyed to Oregon utilities under the Commission-approved renewable avoided cost power purchase agreements for PURPA qualifying facilities during the renewable deficiency period in such contracts.

Proposed OAR 860-091-0020

Aggregate Electrical Capacity

(1) For purposes of compliance with the standard in ORS 469A.210(2), each electric company's aggregate electrical capacity is the total nameplate capacity of the electric company's generation resources to serve Oregon load.

(2) For electric companies making retail sales in multiple jurisdictions, the nameplate capacity of generation resources to serve Oregon load is the total nameplate capacity of the electric company's system generation multiplied by Oregon's generation allocation factor.

CREA-REC Comments:

The Commission should revise this definition to be consistent with the definition proposed above in our comments under the definitions section. There are at least two distinct issues implicated by this section of the rule. First, CREA and REC recommend a definition of "electrical capacity" that is consistent with the generator's contribution to the utility's capacity needs (commonly referred to as contribution to peak capacity). Second, regardless of how the Commission defines "electrical capacity," the rules must use the same measurement criteria for both the numerator and the denominator of the compliance equation, and therefore proposals to use Oregon peak load of a utility in the denominator cannot be adopted. These topics are discussed in turn below.

1. Meaning of "Electrical Capacity"

The statute uses the term "electrical capacity" for purposes of measuring compliance by determining the numerator (electrical capacity of the facilities used by the utility to meet the requirement) and the denominator (electrical capacity of the utility's entire generation portfolio). *See* ORS 469A.210(2). The same term is used in both the numerator and the denominator of the statute's compliance equation. The best interpretation of this statutory provision, when read in context and consistent with the overall policy of the legislation, is that the *electrical* capacity means the facility's ability to contribute electrical capacity to the utility, which is regularly identified in the utility's integrated resource plan ("IRP").

The term "aggregate *electrical* capacity" is used in ORS 469A.210(2) to describe the eight-percent requirement and to measure compliance with the requirement by facilities that meet the statutory criteria, whereas the term "generating capacity" is used in ORS 469A.210(2)(a) to describe qualifying criteria, which is the 20-MW maximum size of facilities qualifying as small-scale. The proposed rule improperly reduces the meaning of both "electrical capacity" and "generating capacity" to be simply the "nameplate capacity."

However, it is a basic maxim of statutory construction that different terms in a statute are presumed to have different meanings. *See Baker v. Croslin*, 359 Or 147, 157, 376 P3d 267 (2016) (alternative terms do not mean the same thing, unless there is evidence of the statute to the contrary). Because the legislature used different words, it is presumed to have intended a different meaning for the terms "electrical capacity" and "generating capacity."

The ordinary meaning of the term "generating capacity" is the maximum generating capacity. In other words, the maximum generation at any instant, i.e., the maximum capacity *the individual facility* could potentially *generate* under ideal conditions. If a facility has a generating capacity of 20 MW or less, it can qualify as a facility used by the utility to meet the eight-percent target (assuming it meets the other requirements).

In contrast, the term “electrical capacity” is different from “generating capacity” and should therefore have different meaning. “Electrical capacity” is used in the context of the electric company’s electrical capacity and should mean the facility’s ability to contribute electrical capacity to the utility. At the insistence of the utilities, the Commission has used these types of “electrical capacity” figures for determining the avoided cost *of capacity* supplied by various renewable resource types since 2014. *See In Re Public Utility Commission of Oregon: Investigation Into Qualifying Facility Contracting and Pricing*, OPUC Docket No. UM 1610, Order No. 14-058, at 15 (Feb. 24, 2014). This is a well-established measurement criteria to determine the electrical capacity of a specific resource type. *See* Docket No. UM 1719. It is therefore reasonable to use this measure of electrical capacity for purposes of this statute.

Each electric company’s “aggregate electrical capacity” would be the sum of this measurement for all generating facilities owned or under long-term contract of the utility, and eight percent of such aggregate electrical capacity must come from facilities with “generating capacity” of 20 MW or less and otherwise meeting the requirements of ORS 469A.210. Had the legislature intended for the eight-percent target to mean that only eight percent of the utility’s aggregate *generating* capacity would come from small-scale facilities, it would have used the term *generating* capacity instead of *electrical* capacity in the clauses of the statute that establish the eight-percent compliance target.

For example, in the case of PacifiCorp, the 2017 IRP lists the capacity contribution to summer peak for PacifiCorp’s existing resources in Table 5.2, which includes 5,919 MW of Pulverized Coal, 2,377 MW of Gas-CCCT, 357 MW of Gas-Other, 958 MW of Hydroelectric, 426 MW of DSM, 294 MW of Renewables, 705 MW of Qualifying Facilities – Renewables, 267 MW of Purchases (not hydroelectric, renewables, or natural gas), 146 MW of Qualifying

Facilities (non-Renewable), and 195 MW of Interruptible Contracts – for a total capacity contribution at summer peak of 11,645 MW.

The maximum generating capacity of these resources is much larger, but several resource types contribute less than their maximum generating capacity to the electrical capacity needs of PacifiCorp, which is demonstrated in Tables 5.3, 5.4, 5.5, 5.6, 5.7, 5.9, and 5.10, where PacifiCorp shows the maximum generating capacity of the various plants by resource type and the capacity contribution of each plant. Those tables are attached hereto for reference.

Generally speaking, the utility's coal and gas-fired plants will have capacity contribution that is equal to the plant's maximum generating capacity, whereas a renewable plant (such as wind or solar) will have a capacity contribution that is some fraction of its maximum generating capacity. In the 2017 IRP, PacifiCorp explained, "The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability." *PacifiCorp 2017 IRP* at 87. For generating facilities in its west balancing authority, PacifiCorp estimated the capacity contribution of wind facilities to be 11.8 percent of maximum generating capacity, the capacity contribution of fixed tilt solar facilities to be 53.9 percent, and the capacity contribution of tracking solar facilities to be 64.8 percent. *Id.* at 88.

Thus, as PacifiCorp already does in its IRP, the Commission could use these same calculations for purposes of the administrative rules. PacifiCorp already calculates the denominator of the compliance equation in this manner in its IRP as noted above. The same calculation could easily be performed for the numerator of the equation consisting of the eligible small-scale community-based facilities. In the case of wind and solar facilities qualifying as small-scale community-based facilities, the capacity contribution values could be used to calculate the numerator of the equation to evaluate compliance with ORS 469A.210, by reducing the maximum generating capacity of the individual facilities by the applicable capacity contribution percentage. In the case of qualifying hydropower and other baseload renewable facilities, PacifiCorp would assume 100 percent capacity contribution as it does in its IRP and its avoided cost calculations. This is reasonable because baseload resources generally have higher capacity factors that are more in line with thermal generation. Additionally, there are and will be fewer small-scale community-based hydropower and baseload resources over time, and it is more controversial and administratively difficult to determine accurate numbers.

To illustrate further with a simplified example, if PacifiCorp were to meet the entire eight-percent compliance requirement with small-scale community-based tracking solar facilities, the following equations would evaluate the amount of maximum generating capacity of such facilities needed to meet the requirement:

Eight Percent of Systemwide Aggregate Electrical Capacity = 931.6 MW

(11,645 MW x 0.08 = 931.6 MW)

Oregon Allocation of Systemwide Aggregate Electrical Capacity = 248.97 MW

(931.6 MW x 0.26725 = 248.97 MW)

Generating Capacity Needed = **384.2 MW of tracking solar**

(248.97 MW x (100/64.8) = 384.2 MW)

As can be seen, PacifiCorp would need an overall maximum generating capacity of 384.2 MW of tracking solar facilities that meet the small-scale community-based criteria. In reality, PacifiCorp would likely acquire or renew contracts with some mixture of various small-scale resource types, but this illustrates the simplicity of the calculation and the magnitude of the compliance requirement under CREA's and REC's proposal.

For purposes of implementing the statutory definitions and compliance requirement in this rulemaking, CREA and REC recommend that the Commission develop an "electrical capacity" percentage that would apply for different resource types used for compliance (numerator) and making up the utility's generation fleet (denominator) to be standardized in the administrative rules for each covered electric company, which currently includes only PacifiCorp and Portland General Electric Company ("PGE"). Because the two utilities may have different peak capacity needs, the rules would provide a different standardized figure for each resource type for each utility.

CREA and REC support using specific numbers in administrative rules based on the figures for contribution to peak that the utilities have developed in their most recent IRPs, rather than frequent updates. First, using a standardized figure for each company available in the administrative rules (as opposed to a new figure in each IRP cycle) will provide more predictability as to the compliance requirement and will prevent gaming of the measurement in the IRPs and other proceedings. Second, the IRP process can be controversial, and there is no real opportunity to review, challenge or obtain a Commission decision on specific IRP inputs like the capacity contribution of variable generation resources. Here, PacifiCorp and PGE have a vested interest in obtaining a specific number, and they should not be trusted to unilaterally set whether they are in compliance with the small-scale community-based renewable mandate.

Finally, we stress that the use of contribution to peak capacity will not present an undue burden on the Commission or the utilities. These are calculations that the utilities already make for purposes of setting avoided cost rates from capacity contribution figures developed in the

IRPs and reviewed and approved by the Commission and stakeholders. As noted above, PacifiCorp already calculates the denominator of the equation in its IRP. Using the contribution to peak instead of nameplate capacity would merely require adding another column or two to the existing compliance spreadsheets to calculate aggregate electrical capacity of the eligible generators and the utility's overall generation portfolio. In the context of utility regulation and implementation of other RPS compliance requirements, this is not an undue burden.

2. Peak Load for Oregon Should Not Be Used in Denominator

Previously in the rulemaking, some parties have suggested the denominator of the equation should be peak load in Oregon, and we therefore comment in opposition to that proposal.

Peak load is directly contradictory to the statutory language. There is no way that "electrical capacity" as used in the statute or by commonly understood and accepted use of the term in the utility industry can be construed to mean peak load. Capacity is a characteristic of a generator of electric energy, and load is a characteristic of an end user of electric energy.

Additionally, the language of the statute requires that the same measurement metric be used in both the numerator and the denominator, but the "peak load" of the facilities used by the utility to meet the requirement (which is the numerator) makes no sense. A small-scale community-based generator does not have a "peak load." Some parties' proposal to use "peak load" in the denominator contradicts the statutory language and commonly understood definitions of utility industry terms.

In sum, therefore, if the Commission maintains the proposed rule's use of nameplate capacity as the meaning for "electrical capacity" in the numerator, the rules must also use nameplate capacity of the utility's generation portfolio as the meaning for electrical capacity in the denominator.

Proposed OAR 860-091-0030

> *Eligible Renewable Energy Projects*
>
> *(1) Renewable energy projects used to comply with the standard in ORS 469A.210 must be located in the State of Oregon.*
>
> *(2) For each renewable energy project used to comply with the standard in ORS 469A.210(2), the electric company must show ownership of the renewable attributes of the energy generated by the project during the compliance year. A renewable energy project for which the electric company does not own the renewable attributes during the compliance year may not be used to comply with the electrical capacity standard in ORS 469A.210(2).*
>
> *(3) Notwithstanding section (2), if the electric company owns the renewable attributes for only a portion of the energy generated by the renewable energy project, a share of the project's capacity that is proportionate to the electric company's ownership interest in the renewable attributes of the project's output can be used for compliance with the standard in ORS 469A.210.*

CREA-REC Comments

Subpart (1) of this provision of the draft rule appropriately limits the facilities to facilities located in Oregon. This aspect of the proposed rule is consistent with the statutory language and purpose of the legislation to ensure that such facilities are part "of this state's energy future" as ORS 469A.210(1) proclaims to be the policy of the legislation. Developing solar facilities in Utah would do nothing to make such facilities an essential element or Oregon's energy future.

Subparts (2) and (3) of this provision appropriately require the utility to own the renewable attributes of the qualifying small-scale facility. This treatment is consistent with the statutory language. The RPS expressly references the requirement in ORS 469A.210 when discussing the limitations on use of renewable energy certificates for other purposes. Most directly, the RPS states, "An electric utility or electricity service supplier that uses a renewable energy certificate to comply with a renewable portfolio standard imposed by a state other than this state may not use the same renewable energy certificate to comply with a renewable portfolio standard established under ORS 469A.005 *to 469A.210*." ORS 469A.140(5) (emphasis added). It must also follow that the utility could not use the renewable energy certificate for some other purpose, such as sale to another party, and that the utility must itself own the renewable energy certificate used for purposes of complying with ORS 469A.210.[3]

Parties asserted at the public hearing that a capacity-based RPS standard, such as that in ORS 469A.210, cannot be understood to require the utility to own the renewable attributes. But that is demonstrably wrong. As noted, Oregon's RPS law expressly states that the renewable attributes used for compliance with its requirements, *including* ORS 469A.210, cannot be used for compliance with other state's RPS laws. ORS 469A.140(5). In addition, in response to arguments by utilities that a project did not need to own the renewable energy certificates to qualify as renewable under ORS 469A.210, the community renewable standard was amended in 2017 to add the language expressly stating that eligible small-scale facilities must "generate electricity utilizing a type of energy described in ORS 469A.025. . . " 2017 Or Laws ch 452 § 1. The renewable energy certificate is what proves such facilities meet these criteria. *See* ORS 469A.130 (stating ODOE "shall establish a system of renewable energy certificates that can be used by an electric utility or electricity service supplier to establish compliance with the applicable renewable portfolio standard").

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[3] If the utility could claim compliance without purchasing and owning the bundled energy and renewable energy certificates produced from the facility, there would also be a double counting violation of Federal Trade Commission regulations regarding environmental claims.

The suggestion that capacity-based standards never require ownership of RECs is wrong. Montana's community renewable energy standard was also a capacity-based standard that required acquisition of 50 MW of community-based facilities and, like Oregon's RPS, required acquisition of the renewable energy certificates from such facilities. *E.g.*, Montana Code Ann. § 69-3-2004(3)(b) (stating, "Beginning January 1, 2012, as part of their compliance with subsection (3)(a), public utilities shall purchase both the renewable energy credits and the electricity output from community renewable energy projects that total at least 50 megawatts in nameplate capacity"). In the industry, it is generally understood that a party must own the renewable attributes in order to claim the benefits of those attributes, whether the claim is made for compliance purposes or otherwise. There is nothing inherently inconsistent between ownership of the renewable attributes of the generation and a capacity-based standard.

Parties have pointed to the former solar capacity requirement in former ORS 757.370 as an example of a capacity-based standard that did not require ownership of renewable energy certificates.[4] But this comparison is inapt. Generally stated, ORS 757.370 created a solar capacity standard under which the electric companies were each required to acquire a proportionate share of a statewide 20 MW of nameplate capacity from large solar systems by 2020. *See In the Matter of a Rulemaking Regarding Solar Photovoltaic Energy Systems*, Docket No. AR 538, Order No. 10-200 (May 28, 2010) (adopting rules for solar capacity standard). Oregon's solar capacity carve out was not contained in the RPS provisions and was not subject to the RPS's statutory bar against using the renewable attributes for other purposes. Instead, the

[4] This provision was in effect from 2009 to 2016, when the legislature repealed it in Senate Bill 1547. 2009 Or Laws ch 748 § 3; 2010 Or Laws ch 79 § 2; repealed by 2016 Oregon Laws, ch 28 § 23, eff. Mar. 8, 2016.

solar capacity standard was located at former ORS 757.370, and there was no express bar against using the renewable attributes with the solar capacity resources for other purposes. Thus, the question turns on the legislature's intent, not parties' conception of a capacity-based or energy-based standard.[5]

The Commission should be aware that resolution of this issue will have a significant outcome on the overall effect of ORS 469A.210. If the utility could achieve compliance without owning the renewable attributes of the facility, PacifiCorp will argue it can meet the eight-percent compliance requirement with facilities for which it pays only for brown power under PURPA contracts. Additionally, both utilities will claim compliance through the use of net metering facilities. Under Oregon law, the customer owns the renewable energy certificates created by its net metering system, and therefore the electric company should not use those renewable energy certificates to meet the requirement in ORS 469A.210. *See* OAR 860-022-0075.[6] The utilities should not be allowed to claim compliance without compensating the small-scale community-based facility for the renewable attributes and without providing any premium that would encourage development and continued operation of such facilities.

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[5] It is also not even clear that the utilities could comply with the solar capacity requirement without owning the renewable energy certificates. The issue was apparently never directly addressed because the solar capacity carve-out compliance deadline was not until 2020, and the requirement was repealed before that time. The former administrative rule anticipated that the utility *would* own the renewable energy certificates and allowed for those certificates to also be used in the RPS's energy-based requirements, where it provided: "Each renewable energy certificate associated with the electricity produced by solar photovoltaic energy systems used to achieve, or exceed, the minimum solar photovoltaic capacity standards specified in OAR 860-084-0020 may be used to comply with the renewable portfolio standards established under ORS 469A.005 to ORS 469A.120" OAR 860-084-0070 (repealed by Order No. 17-518).

[6] Additionally, a net metering facility is not the type of utility-scale generation selling its entire net output to the utility that is envisioned as a qualifying project in ORS 469A.210. Instead, it is an individually owned facility that essentially serves the electrical needs of a single customer by offsetting that customer's usage over the year.

Finally, CREA and REC understand this rule makes a distinction between "ownership" of the renewable attributes during the compliance year and retirement of the renewable energy certificates. We understand the distinction is intended to provide some flexibility in the ability to use the renewable energy certificates from the small-scale community-based facilities to also meet the general RPS requirements. We have no objection to this treatment because the effect of the rule is to require the utility to purchase the bundled energy and renewable attributes from the small-scale facility in order for the facility to contribute to the utility's compliance with ORS 469A.210.

Proposed OAR 860-091-0040

> *Compliance Reports*
>
> *(1) No later than June 1, 2025, and no later than June 1 for each year thereafter the electric company must file a report with the Commission demonstrating compliance or explaining in detail any failure to comply, with the standard in ORS 469A.210.*
>
> *(2) The report required in section (1) of this rule must include the following information associated with each owned or contracted qualifying and eligible renewable energy project:*
>
> *(a) The name of the facility;*
>
> *(b) The location of the facility;*
>
> *(c) The in-service date of the facility;*
>
> *(d) The manufacturer's nameplate capacity rating;*
>
> *(e) The execution date of any associated power purchase agreement; and*
>
> *(f) The contracted capacity and output delivery period of any associated power purchase agreement; and*
>
> *(g) Proof of the subject electric company's ownership interest in the renewable attributes of the project output during the compliance period.*

(3) The report required in section (1) of this rule must include the following information regarding the electric company's generation:

(a) The total nameplate capacity of the electric company's generating resources.

(b) The total contracted capacity of all power purchase agreements.

(c) For an electric company making retail sales in multiple jurisdictions, the Oregon generation allocation factor from the most recently concluded Oregon general rate case.

CREA-REC Comments:

CREA and REC support this proposed rule's requirement for ongoing annual compliance filings to ensure compliance going forward. ORS 469A.210 creates a continuing obligation after the first compliance year where penalties may apply beginning in 2025, and it provides no provisions allowing for banking of the renewable energy certificates supplied to meet the requirement. Thus, if the contract for the utility's purchase of bundled renewable energy certificates and energy of a particular small-scale community-based facility does not extend beyond 2025, the utility would need to obtain additional complying resources to comply with the eight-percent target in order to comply in a future compliance year.

The utilities have asserted that the statute only requires compliance in 2025 and not thereafter, but that argument is misplaced. The statute specifically states the intent of the eight-percent requirement is to make small-scale community-based facilities an "essential element of this state's energy *future*," ORS 469A.210(1) (emphasis added), and it further states that "by 2025" the eight-percent requirement must be met. ORS 469A.210(2). The obvious intent is that that these facilities become *and remain* an essential element of the state's energy future. There is no basis to conclude the legislature intended for the utilities to achieve compliance by some date in 2025 and thereafter cease purchasing power from this essential element of the state's energy future.

PacifiCorp argues that the eight percent requirement is only a one time obligation on the grounds that other provisions in the renewable portfolio standard state that the obligations apply in a specific year "and subsequent calendar years" and that the legislature should have included similar language in the eight percent requirement if it was to be in effect in subsequent years. *See* ORS 469A.052(1)(h) ("At least 50 percent of the electricity sold by an electric company to retail electricity consumers in the calendar year 2040 and subsequent calendar years must be qualifying electricity."). There is a more obvious and common sense reason for the differing language. The primary renewable portfolio standard provisions have different compliance requirements for different years (i.e., 5% in 2011-2014, 15% in 2015-2019, etc.). In contrast, there is no gradual increase in the eight percent requirement and hence no need to carefully distinguish which years which obligation is triggered. There is a simple requirement that must be met no later than 2025 and that obligation is ongoing.

PacifiCorp apparently hopes to be relieved of the requirement to comply after 2025 because it has many expiring contracts with small-scale facilities that expire shortly after 2025 – a fact that was not apparent until after the Commission-required data collection was recently completed. The Commission should reject PacifiCorp's interpretation of the statute because it contradicts the obvious intent of the legislature.

Finally, CREA and REC recommend that the utilities be directed to complete annual progress reports effective April 1, 2019. Once the rule is finalized, this data should be readily available, and the sooner the level of compliance is known the sooner stakeholders can recommend resource actions in other critical proceedings and planning exercises.

Proposed OAR 860-091-0050

Renewable Energy Attributes

(1) Use of a qualifying project's capacity to meet the standard of ORS 469A.210 does not prevent the electric company from using the renewable energy certificates associated with qualifying projects' output for purposes of meeting a renewable portfolio standard established under ORS 469A.050 during the compliance year.

(2) Use of a qualifying project's capacity to meet the standard of ORS 469A.210 does not prevent the electric company from banking otherwise eligible renewable energy certificates associated with qualifying projects' output for purposes of meeting a renewable portfolio standard established under ORS 469A.050 in a subsequent year.

CREA-REC Comments

As noted above, CREA and REC have no objection to these provisions. The critical requirements of the statute are that the utility must purchase the bundled energy and renewable attributes of the facility in the compliance year. If the utility uses the renewable energy certificates for other compliance purposes under the more general requirements of Oregon's RPS, the statutory intent is not frustrated.

Proposed OAR 860-091-0060

Implementation Plans

Starting in 2021 and every year thereafter, an electric company must incorporate its plan to achieve or exceed, and maintain, the standard in ORS 469A.210 into its renewable portfolio standard implementation plans filed pursuant to OAR 860-083-0400.

CREA-REC Comments

CREA and REC agree that the utilities should include ORS 469A.210 in their RPS implementation plans, but propose that the utilities should start addressing this issue in the next implementation plan they file. The draft proposed rule delays this issue until 2022, and it is not clear why this aspect of the rule should not take effect immediately with the rest of the rule.

The utilities are required to file their next implementation plans on or before January 1 in even-numbered years, OAR 860-083-0400(1), so their next one is due January 1, 2020. This means that if they are not required to include this standard in their implementation plan until January 1, 2021 the practical effect is that it will be delayed until 2022. There is plenty of time over the next year to include this in their next 2020 implementation plan.

Proposed OAR 860-091-0070

Cost Recovery

An electric company may request recovery of its prudently incurred costs to comply with the Standard in ORS 469A.210 in an automatic adjustment clause proceeding filed at the Commission pursuant to ORS 469A.120.

CREA-REC Comments

CREA and REC do not have any concerns with this aspect of the proposed rule.

Additional Comments

The draft proposed rule does not address compliance and penalties, but such provisions should be clarified in the final rules. The RPS charges the Commission with penalizing electric companies that fail to comply with this requirement. It provides: "If an electric company or electricity service supplier that is subject to a renewable portfolio standard under ORS 469A.005 to 469A.210 fails to comply with the standard in the manner provided by ORS 469A.005 to 469A.210, the Public Utility Commission may impose a penalty against the company or supplier in an amount determined by the commission." ORS 469A.200. Without penalties and clarity in the rule, the affected utilities may elect to simply violate the statutory requirement.

While CREA and REC appreciate that, after 12 years, the Commission is finally taking action in response to the legislative directive regarding the eight-percent provision, we have very serious concerns with the Commission's willingness to seriously consider certain recommendations by the utilities throughout this process that have been obviously intended to minimize and undermine the legislative intent – such as use of peak load in the denominator.

We are further troubled that, based on the record, including the compliance template circulated, that the Commission has not seriously considered CREA's and REC's reasonable position regarding the use of the same capacity contribution numbers used by the utilities in their IRPs and avoided cost rates paid to such small-scale facilities for the capacity value they supply to the utility. To the best of our knowledge, the Commission did not even ask the utilities to provide these numbers for the numerator or the denominator, and instead allowed the compliance templates to portray numbers based on arguments clearly contrary to law (such as peak load).

At the hearing, the Commission indicated that CREA and REC should calculate the compliance status under a capacity contribution metric. However, based on the data provided, it was not even possible for CREA and REC to confidently calculate the current status of compliance under our proposal because no data was supplied for the denominator portion of the equation that corresponded to the data supplied for the numerator of the equation.

CREA and REC are concerned that, if the Commission does not adopt our recommendations, any final order will not even include any estimate of the status of current and projected compliance under our recommendations. The Commission's final order may list a number of options under consideration and where the utilities stand under each of those options, all of which may show the utilities close to or meeting the eight-percent requirement. This will give an observer a false impression that the utilities are on track for compliance under all competing proposals. We are not surprised that the utilities spent the last few years refusing to provide CREA and REC with information; however, CREA and REC are frankly stunned that the Commission itself will gather data on *all* other options, except the ones recommended by as the two organizations most directly involved in the eight percent requirement over the last decade.

The utilities, in this and other related proceedings, consistently make their opposition to the development small-scale community-based renewable resources well known. That is their prerogative. But the Commission should uphold and implement the underlying intention of the legislature in the promulgation of these rules.

Dated: February 21, 2019.

Respectfully submitted,

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Attachment 1

Excerpt of PacifiCorp’s 2017 Integrated Resource Plan

The 2017 IRP relies on PacifiCorp's December 2016 load forecast. Table 5.1 shows the annual summer coincident peak load stated in megawatts as reported in the capacity load and resource balance, before any load reductions from Class 2 DSM and private generation. The system summer peak load grows at a compounded average annual growth rate (CAAGR) of 0.85 percent over the period 2017 through 2026.

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System	10,164	10,277	10,384	10,486	10,608	10,718	10,804	10,907	11,028	11,049

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2017 summer coincident peak, PacifiCorp owns or has interests in resources with an expected system summer peak capacity of 11,645 MW. Table 5.2 provides anticipated system summer peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2017. Note that capacity ratings in the following tables provide resource capacity value at the time of system coincident peak, rounded to the nearest megawatt.

Table 5.2 – 2017 Capacity Contribution at System Summer Peak for Existing Resources

Resource Type[1/]	L&R Balance Capacity at System summer peak (MW)[2/]	Percent of Total (%)
Pulverized Coal	5,919	50.8%
Gas-CCCT	2,377	20.4%
Gas-Other	357	3.1%
Hydroelectric	958	8.2%
DSM[3/]	426	3.7%
Renewables	294	2.5%
Qualifying Facilities—Renewables	705	6.1%
Purchase[4/]	267	2.3%
Qualifying Facilities	146	1.3%
Interruptible Contracts	195	1.7%
Total	**11,645**	**100%**

1/ Sales and Non-Owned Reserves are not included.
2/ Represents the capacity available at the time of system summer peak used for preparation of the capacity load and resource balance. For specific definitions by resource type see the section entitled "Load and Resource Balance Components" later in this chapter.
3/ DSM includes existing Class 1 (direct load control) and Class 2 (energy efficiency) programs.
4/ Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

Table 5.3 lists PacifiCorp's existing coal-fueled thermal plants and Table 5.4 lists existing natural-gas-fueled plants. The assumed end-of-life dates are used for the 2017 IRP modeling of existing coal resources.

Table 5.3 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Cholla 4	100	AZ	2042	387
Colstrip 3	10	MT	2046	74
Colstrip 4	10	MT	2046	74
Craig 1	19	CO	2034	82
Craig 2	19	CO	2034	82
Dave Johnston 1	100	WY	2027	106
Dave Johnston 2	100	WY	2027	106
Dave Johnston 3	100	WY	2027	220
Dave Johnston 4	100	WY	2027	330
Hayden 1	24	CO	2030	45
Hayden 2	13	CO	2030	33
Hunter 1	94	UT	2042	418
Hunter 2	60	UT	2042	269
Hunter 3	100	UT	2042	471
Huntington 1	100	UT	2036	459
Huntington 2	100	UT	2036	450
Jim Bridger 1	67	WY	2037	354
Jim Bridger 2	67	WY	2037	359
Jim Bridger 3	67	WY	2037	345
Jim Bridger 4	67	WY	2037	350
Naughton 1	100	WY	2029	156
Naughton 2	100	WY	2029	201
Naughton 3[1/]	100	WY	2029	280
Wyodak	80	WY	2039	268
TOTAL – Coal				**5,919**

[1/] Naughton Unit 3 may be retired at the end of 2018.

Table 5.4 – Natural-Gas-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Chehalis	100	WA	2043	464
Currant Creek	100	UT	2045	533
Gadsby 1	100	UT	2032	64
Gadsby 2	100	UT	2032	69
Gadsby 3	100	UT	2032	105
Gadsby 4	100	UT	2032	40
Gadsby 5	100	UT	2032	40
Gadsby 6	100	UT	2032	40
Hermiston (owned)	50	OR	2036	227
Lake Side	100	UT	2047	530
Lake Side 2	100	UT	2054	623
TOTAL – Gas and Combined Heat & Power				**2,734**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 2,333 MW of wind resources. Since the 2015 IRP Update, the Company has entered into power purchase agreements totaling 40 MW.

Table 5.5 shows existing wind facilities owned by PacifiCorp, while Table 5.6 shows existing wind power purchase agreements.

Table 5.5 – Owned Wind Resources

Wind Project	State	Capacity (MW)	L&R Balance Capacity at System summer peak (MW)
Foote Creek I[1/]	WY	32	6
Leaning Juniper	OR	101	12
Goodnoe Hills Wind	WA	94	11
Marengo	WA	140	17
Marengo II	WA	70	8
Glenrock Wind I	WY	99	16
Glenrock Wind III	WY	39	6
Rolling Hills Wind	WY	99	16
Seven Mile Hill Wind	WY	99	16
Seven Mile Hill Wind II	WY	20	3
High Plains	WY	99	16
McFadden Ridge 1	WY	29	4
Dunlap 1	WY	111	18
TOTAL – Owned Wind		**1,032**	**148**

[1/] PacifiCorp's share is 32 MW of the 40 MW project.

Table 5.6 – Non-Owned Wind Resources

Power Purchase Agreements/Exchanges	State	PPA or QF	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Combine Hills	OR	PPA	41	5
Foote Creek IV	WY	PPA	17	3
Rock River I	WY	PPA	50	8
Stateline Wind	OR/WA	PPA	175	21
Three Buttes Wind Power (Duke)	WY	PPA	99	16
Top of the World	WY	PPA	200	32
Wolverine Creek	ID	PPA	65	10
Casper Wind (Chevron)	WY	QF	17	3
Chopin	WA	QF	10	1
Foote Creek II	WY	QF	2	0
Foote Creek III	WY	QF	25	4
Latigo Wind	UT	QF	60	9
Mariah Wind	OR	QF	10	1
Meadow Creek Project – Five Pine	ID	QF	40	6
Meadow Creek Project – North Point	ID	QF	80	13
Mountain Wind Power I	WY	QF	61	10
Mountain Wind Power II	WY	QF	80	13
Orchard Wind[1/]	WA	QF	40	5
Oregon Wind Farms I & II	OR	QF	65	8
Orem Family Wind	OR	QF	10	1
Pioneer Wind Park I	WY	QF	80	13
Power County Wind Park North	ID	QF	23	4
Power County Wind Park South	ID	QF	23	4
Spanish Fork Wind Park 2	UT	QF	19	3
Three Mile Canyon	WA	QF	10	1
Small QF	WY	QF	0.2	0
TOTAL – Purchased Wind			**1301**	**191**

[1/] New since 2015 IRP Update

Solar

PacifiCorp has a total of 54 solar projects under contract representing 1,164 MW of nameplate capacity. Of these, two projects totaling 100 MW are new since the 2015 IRP Update.

Table 5.7 – Non-Owned Solar Resources

Power Purchase Agreements/Exchanges	PPA or QF	State	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Black Cap	PPA	OR	2	1
Utah Solar PV Program	PPA	UT	2	1
Old Mill	PPA	OR	5	3
Oregon Solar Incentive Projects	PPA	OR	10	5
Small Solar	QF	UT	0.5	0
Adams Solar Center	QF	OR	10	6
Bear Creek Solar Center	QF	OR	10	6
Beatty Solar	QF	OR	5	3
Beryl Solar	QF	UT	3	1
Black Cap Solar II	QF	OR	8	5
Bly Solar Center	QF	OR	9	6
Buckhorn Solar	QF	UT	3	1
Cedar Valley Solar	QF	UT	3	1
Chiloquin Solar	QF	OR	10	5
Collier Solar	QF	OR	10	6
Elbe Solar Center	QF	OR	10	6
Enterprise Solar	QF	UT	80	47
Escalante Solar I	QF	UT	80	47
Escalante Solar II	QF	UT	80	47
Escalante Solar III	QF	UT	80	47
Ewauna Solar	QF	OR	1	1
Ewauna Solar 2	QF	OR	3	2
Fiddler's Canyon Solar 1-3	QF	UT	9	5
Granite Mountain – East	QF	UT	80	47
Granite Mountain – West	QF	UT	50	30
Granite Peak Solar	QF	UT	3	1
Greenville Solar	QF	UT	2	1
Iron Springs	QF	UT	80	47
Ivory Pine Solar	QF	OR	10	6
Laho Solar	QF	UT	3	1
Merrill Solar	QF	OR	10	6
Milford Flat Solar	QF	UT	3	2
Milford Solar 2	QF	UT	3	1
Norwest Energy 2 (Neff)	QF	OR	10	6
Norwest Energy 4 (Bonanza)	QF	OR	6	4
Norwest Energy 7 (Eagle Point)	QF	OR	10	6
Norwest Energy 9 Pendleton	QF	OR	6	3
OR Solar 2, LLC (Agate Bay)	QF	OR	10	6
OR Solar 3, LLC (Turkey Hill)	QF	OR	10	6
OR Solar 5, LLC (Merrill)	QF	OR	8	5
OR Solar 6, LLC (Lakeview)	QF	OR	10	6
OR Solar 7, LLC (Jacksonville)	QF	OR	10	6
OR Solar 8, LLC (Dairy)	QF	OR	10	6
Pavant Solar	QF	UT	50	29
Pavant Solar II LLC	QF	UT	50	30
Pavant Solar III LLC[1/]	QF	UT	20	12
Quichapa Solar 1-3	QF	UT	9	5
South Milford Solar	QF	UT	3	2
Sprague River Solar	QF	OR	7	5
Sweetwater Solar[1/]	QF	WY	80	48
Three Peaks Solar	QF	UT	80	47
Tumbleweed Solar	QF	OR	10	5
Utah Red Hills Renewable Park	QF	UT	80	47
Woodline Solar	QF	OR	8	5
TOTAL – Purchased Solar			**1,164**	**690**

[1/] New since 2015 IRP Update

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. At least one project is located in each state in PacifiCorp's service territory.

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years over most of PacifiCorp's service territory. Utah, however, has seen tremendous growth—an approximate 180 percent increase year over year—in the amount of residential solar being interconnected. Table 5.8 provides a breakdown of net metered capacity and customer counts from data collected on November 30, 2016.

Table 5.8 – Net Metering Customers and Capacities

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	184,548.20	793.66	884	658.40	1130.11
Capacity (percentage)	98.16%	0.42%	0.47%	0.35%	0.60%
Number of customers	22,355	198	4	14	60
Customer (percentage)	98.78%	0.87%	0.02%	0.06%	0.27%

[1/] Gas includes: biofuel, waste gas, and fuel cells
[2/] Mixed includes projects with multiple technologies, one project is solar and biogas and the others are solar and wind

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 127 MW of other hydroelectric resources.[1] These resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in

[1] PacifiCorp's 2016 10-K shows 1,135 MW of Net Facility Capacity.

its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.9, which shows 2017 capacity included in the load and resource balance.

Table 5.9 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System summer peak (MW)
Hydroelectric	89
Qualifying Facilities—Hydroelectric	38
Total Contracted Hydroelectric Resources	**127**

Table 5.10 provides the operational capacity for each of PacifiCorp's owned hydroelectric generation facilities at system summer peak (2017).

Table 5.10 – PacifiCorp Owned Hydroelectric Generation Facilities – Load and Resource Balance Capacities

Plant	State(s)	L&R Balance Capacity at System summer peak (MW)
West		
Big Fork	MT	4
Klamath – Dispatch	CA	56
Klamath – Flat	CA	11
Klamath – Shape	OR	86
Lewis – Dispatch	WA	390
Lewis – Shape[1/]	WA	94
Rogue	OR	31
Small West Hydro[2/]	CA/OR/WA	2
Umpqua – Flat	OR	24
Umpqua – Shape	OR	89
East		
Bear River – Dispatch	ID/UT	53
Bear River – Shape	ID/UT	16
Small East Hydro[3/]	ID/UT/WY	14
TOTAL – Hydroelectric before Contracts		**869**
Plus Hydroelectric Contracts		**127**
TOTAL – Hydroelectric with Contracts		**996**

[1/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp
[2/] Includes Bend, Fall Creek, and Wallowa Falls
[3/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.11 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2020 and that other projects currently in relicensing will receive new operating licenses, but that additional

Pages Omitted

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, position, and available FOTs.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, existing Class 1 DSM, sales, and non-owned reserves. Categories in the obligation section include load (net of private generation), interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the preferred portfolio.

Existing Resources
A description of each of the resource categories follows:

Thermal
This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system summer or winter peak, as applicable. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. This includes the existing fleet of coal-fueled units, six natural-gas-fueled plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

Hydroelectric
This category includes all hydroelectric generation resources operated in the PacifiCorp system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system summer peak, an approach consistent with current Western Electric Coordinating Council (WECC) capacity reporting practices. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is on the west side of the PacifiCorp system.

Renewable
This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability. PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area, which is presented in Volume II, Appendix N (Wind and Solar Capacity Contribution Study). The resulting capacity contribution values are shown in Table 5.13 below.

Table 5.13 Summer Peak Capacity Contribution Values for Wind and Solar

	East Balancing Authority Area			West Balancing Authority Area		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
Capacity Contribution Percentage	15.8%	37.9%	59.7%	11.8%	53.9%	64.8%

Purchase

This includes all major purchases contracts for firm capacity and energy in the PacifiCorp system.[4] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities (QF)

All QFs that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Dispatchable Load Control (Class 1 DSM)

Existing dispatchable load control program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources.

Sales

This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Non-owned Reserves

Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves as a balancing are authority for load and generation that are in PacifiCorp's balancing authority area (BAA) but not owned by PacifiCorp's. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 3 MW and 38 MW on the west and east BAAs, respectively. The non-owned reserves do not contribute to the energy obligation because the requirement is for capacity only.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less private generation, existing Class 2 DSM, new Class 2 DSM from the preferred portfolio, and interruptible contracts. The following are descriptions of each of these components:

[4] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity that are treated as firm purchases. PacifiCorp has the right to curtail the customer's load as needed for economic purposes. The customer in turn may or may not pay market-based rates for energy used during a curtailment period.