Upper Klamath Basin
America's Water Infrastructure Act
Affordable Power Measures Report

Interior Region 10 · California-Great Basin

Estimated cost of preparation of
Affordable Power Measures and
Power Cost Benchmark reports
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Mission Statements

The Department of the Interior (DOI) conserves and manages the Nation's natural resources and cultural heritage for the benefit and enjoyment of the American people, provides scientific and other information about natural resources and natural hazards to address societal challenges and create opportunities for the American people, and honors the Nation's trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities to help them prosper.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Upper Klamath Basin America's Water Infrastructure Act Affordable Power Measures Report

Interior Region 10 · California-Great Basin

Prepared for the Bureau of Reclamation by Kleinschmidt Associates and Lloyd Reed Consulting under Contract No. 47QRAA18D005P.

Cover Photo: F and FF pumping plants located where the Klamath Straits Drain empties into the Klamath River. 2004. (Reclamation)

Contents

Executive Summary

Purpose and Scope of the Affordable Power Measure Report

This Affordable Power Measures ("APM") Analysis and Report has been prepared by the United States Bureau of Reclamation ("Reclamation") as the Secretary of the Interior's (Secretary's) response to certain provisions outlined in the America's Water Infrastructure Act of 2018 (Pub. L. 115-270, "AWIA") regarding the reduction of power costs to agricultural water users in the Upper Klamath Basin. Specifically, Section 4308 of the AWIA amended the Klamath Basin Water Supply Enhancement Act of 2000 (Pub. L. 106-498) to address power and water management in the Klamath Basin, including reduction of power costs (Enhancement Act as amended, Section 4(c)). The Enhancement Act as amended will hereafter be referred to as the "Enhancement Act."

In satisfaction of these requirements, this APM Report is being submitted to the Committee on Energy and Natural Resources of the U.S. Senate and the Committee on Natural Resources of the U.S. House of Representatives (collectively "the Committees"). A separate companion report - referred to as the Power Cost Benchmark ("PCB") Report - is also being submitted to the Committees as directed by the Enhancement Act.

Affordable Power Measures

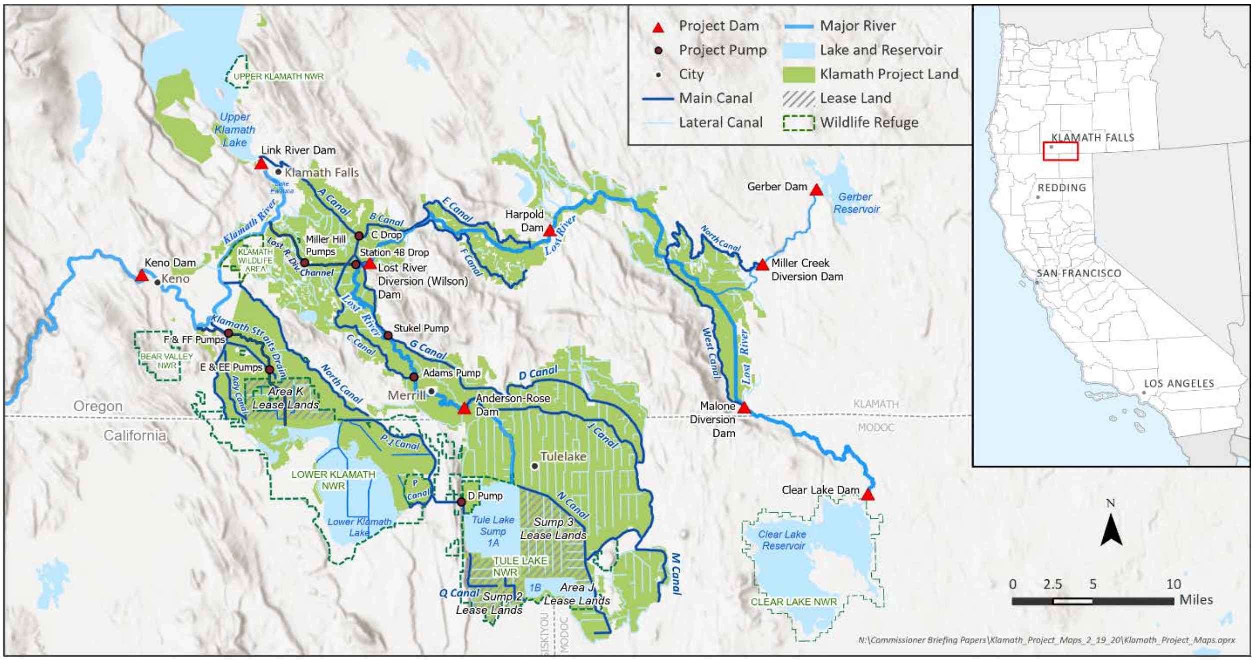
The set of specific actions that have been developed in response to the criteria referenced in the Enhancement Act are referred to in this report as "Affordable Power Measures" or "APMs". APMs are defined as actions that can be undertaken by stakeholders/water users to reduce power costs for irrigation and drainage use in the Upper Klamath Basin to a level equal to or below the Power Cost Benchmark. [1] The methodologies utilized to identify, evaluate, and select the final set of recommended APMs are described in various chapters of this Report.

Description of the Klamath Project

The Secretary of the Interior authorized development of the Klamath Project on May 15, 1905, under provisions of the Reclamation Act of 1902 (32 Stat. 388). The irrigable lands of the Klamath Project are in south-central Oregon (62 percent) and north-central California (38 percent) and cover lands in Klamath County, Oregon, and Siskiyou and Modoc counties in northern California. In addition to providing water that supports the Tule Lake National Wildlife Refuge and the Lower Klamath National Wildlife Refuge, the Project provides full-service water and drainage to approximately 210,000 acres of cropland and pastureland located within the Upper Klamath Basin.

[1] As is described in more detail in the accompanying Power Cost Benchmark Report, the PCB is a per-unit measure (expressed in terms of ¢/kilowatt-hour) of the average cost of power for irrigation and drainage use in Reclamation Projects located in the Pacific Northwest Region and that are similarly situated to the Klamath Project.

Figure ES-1. Map of the Klamath Project showing primary Project features



Map of the Klamath Project showing primary Project features

Beyond the ecosystem benefits that are provided and irrigation customers that are served by the Project, there are a significant number of additional water users irrigating lands that are located within the larger Upper Klamath Basin. These so-called "Off-Project areas" include irrigated lands in Oregon within the watersheds of the Lost, Sprague, Williamson, and Wood rivers. There are water uses located in the Off-Project areas that are considered to be "covered users" under the Enhancement Act (Section 4(a)(1)). Therefore, this APM Analysis evaluates power cost savings measures that have the ability to reduce power costs for covered users located throughout the Upper Klamath Basin.

Additional general information regarding the Klamath Irrigation Project is contained in Chapter 2.0.

Historical Power Costs for Irrigation and Drainage use in the Upper Klamath Basin

At the time of the Klamath Project's development, Reclamation filed for all unappropriated water in the Klamath Basin along with the right to appropriate water for power development at several locations. Reclamation recognized that in order to irrigate the land it was necessary to access power for both drainage and pumping purposes. Although Reclamation had the authority and intent to develop and provide power to the Klamath Project irrigators at the time of the Project's development, inadequate funding in the early years of development had prevented it from doing so.

In 1916 the California Oregon Power Company ("COPCO"), now PacifiCorp, approached Reclamation and proposed building a dam on Upper Klamath Lake to provide better water regulation for COPCO's existing and planned hydropower facilities to be developed on the Klamath

River. In 1917 Reclamation entered into a 50-year contract with COPCO for the construction and operation of Link River Dam that also included provisions for COPCO to provide power at discounted rates to the Klamath Project beneficiaries. Reclamation's contract with COPCO protected irrigation rights and provided the Klamath Project water users with power rates locked in at 1917 levels; this agreement therefore allowed Reclamation to provide the Klamath Project with power for Basin irrigators as was its original intent.

The original COPCO/Reclamation contract was amended in 1956, featuring essentially the same power rates for an additional 50-year period; this agreement was a condition of PacifiCorp's Klamath Hydroelectric Project FERC operating license becoming effective. Later in 1956, a separate COPCO contract provided Off-Project agricultural power users located in the Upper Klamath Basin with reduced power rates similar to those of the On-Project users.

At the expiration of PacifiCorp's FERC license in 2006, the Oregon Public Utility Commission ("OPUC") and the California Public Utility Commission ("CPUC")[2] allowed PacifiCorp to phase in full tariff power rates to agricultural customers in the Basin over a period of several years. The 1956 contract expiration and the FERC and PUCs rulings ended nearly 90 years of reduced or at-cost power rates for Upper Klamath Basin irrigators.

Current Power Costs for Irrigation and Drainage use in the Upper Klamath Basin

The termination of the 1956 PacifiCorp power supply agreements resulted in an increase in power rates for agricultural water users in the Klamath Basin from 0.3 to 0.75 cents per kilowatt-hour (¢/kWh) in 2006 to approximately 11.1 ¢/kWh in Oregon and 15.2 ¢/kWh in California during 2017 - 2018. With these changes, the average water pumping cost on the Klamath Project in 2015 was $45 per acre as compared to an average power cost of $2.25 per acre prior to the 1956 power contract's expiration.

It is important to note that the 1956 power contracts in place with PacifiCorp up until 2006 were unique in that low-cost power supplies were made available not only to federal pumps on the Klamath Project, but also to irrigation districts for their own pumps, and individual On-Project and Off-Project irrigation customers as well. Therefore, the expiration of these agreements in 2006 and the subsequent phase-in to PacifiCorp's full retail tariff rates had a <u>double (or triple) impact</u> of not only significantly increasing costs at federal pumps delivering water supplies (and drainage) to ultimate On-Project users but also in increasing these same water users' individual at-site water distribution costs, and those of their irrigation districts as well. Off-Project water users also endured significantly higher costs by virtue of having to purchase all their on-farm power supply needs from PacifiCorp under full retail tariff rates.

Additional historical context regarding power rates for irrigation and drainage use in the Upper Klamath Basin and the impacts of higher power costs in the Basin following the expiration of the PacifiCorp power purchase agreements in 2006 is provided in Chapter 3. In addition, Chapter 10 of

[2] Collectively, the OPUC and the CPUC are referred to in this Report as "the Rate Commissions", "the Commissions", or "the PUCs".

the PCB Report contains updated calendar Year 2017 – 2018 power cost information for agricultural customers located in the different portions of the Upper Klamath Basin.

APM Analysis Public Stakeholder Process

An important component of the APM Analysis was the opportunity for interested stakeholders to participate in the study process and provide meaningful input into the production of the final APM Report. In particular, many stakeholders have long histories of living and working in the Upper Klamath Basin and their informed insights on the impacts of higher electricity prices on irrigation practices in the Basin were invaluable to the APM Analysis Team.

Interested stakeholders had several different avenues available in which to stay informed of and provide input to the APM Analysis throughout the life of the project. Additional information regarding the public stakeholder process and the multiple opportunities for interested parties to provide feedback to the APM Analysis Team is contained in Chapter 5.

The Comprehensive Agricultural Power Plan Report

In October 2016, Reclamation publicly released the Comprehensive Agricultural Power Plan ("CAPP") Report for the Klamath Basin. The CAPP was an extensive effort initiated by Reclamation and multiple stakeholders to identify, discuss, and screen multiple different alternatives that might help lower overall power costs for both On-Project and Off-Project covered irrigation water users located in the Oregon and California portions of the Upper Klamath Basin.

The CAPP was also initiated in the context of a broader effort to assess many different facets of water use in the Klamath Basin; this process resulted in the Klamath Basin Restoration Agreement ("KBRA") which was finalized by Reclamation and multiple stakeholders in 2010. The KBRA sought to address short-, medium-, and long-term power costs in the Upper Klamath Basin in light of the 2006 PacifiCorp power contracts.

After first providing some historical context regarding power costs in the Upper Klamath Basin, the CAPP Report then described in detail a total of eighteen potential power cost savings measures ("Measures") that were identified by the CAPP Analysis Group. Pre-feasibility study-level economic analyses were performed on all the identified Measures. Once the universe of potential power cost savings Measures was identified and various analyses performed, all the Measures were screened and ranked using nine different criteria including forecasted reductions in power rates, administrative intensity, access to benefits, and environmental impacts. All of the Measures were then grouped into one of three tiers, with Tier-1 containing those Measures that presented the best opportunities to lower power rates in the Basin while Tier-3 contained Measures that either did not reduce power rates or exhibited substantial uncertainties.

Identifying the Affordable Power Measures

In initially defining the broad parameters for the APM Analysis, the APM Analysis Team agreed that the Analysis should utilize the earlier work originally developed for the CAPP as a starting point in order to re-assess and identify viable APMs for the Upper Klamath Basin pursuant to the directives specified in the Enhancement Act. To this end, the Team first reviewed the results from the CAPP Report and developed a list of power cost savings measures to potentially be considered as part of the APM Analysis. Following this initial screening process, the Team chose 12 power cost savings alternatives from the CAPP to be considered as potential Affordable Power Measures in the APM Analysis.[3]

Following multiple rounds of open discussion and preliminary evaluations, the Team then identified several additional cost-savings measures for consideration under the APM Analysis that were not previously analyzed as part of the CAPP study. From the overall list of potential APM candidates, the Team then performed a high-level screening process that resulted in a final list of nine Affordable Power Measures to be evaluated in more detail.[4] In developing the final list of nine potential power cost savings measures, the Team placed a focus on Measures that were judged to be: 1) consistent with the requirements established in the Enhancement Act, 2) economically viable given current and forecasted conditions, 3) consistent with the existing regulatory frameworks in place in Oregon and California, 4) have minimal environmental impacts, and 5) are realistically implementable.

The APM Analysis Group recognized that the potential benefits to be derived from some of the identified power cost savings measures might not be equally distributed across all covered water users in the Upper Klamath Basin due to a variety of factors. However, in screening the various candidate Measures, the APM Analysis Team attempted to craft a package of recommended Measures that - when taken as a whole – is expected to create power cost reduction benefits to Reclamation, the irrigation districts located within the Klamath Project, and both On-Project and Off-Project covered water users in the Upper Klamath Basin.

Detailed Descriptions of the Affordable Power Measures

Each of the nine APMs - as identified above in Table ES-1 - were evaluated independently utilizing multiple sets of criteria that included technical specifications, environmental attributes, siting considerations, and the overall cost/benefit proposition with regard to lowering power costs for irrigation and drainage customers in the Upper Klamath Basin.

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[3] All 12 of the power cost savings alternatives from the CAPP that were selected to be included in the APM Analysis were ranked as either Tier-1 or Tier-2 alternatives under the CAPP's screening process.

[4] One additional means for potentially reducing power costs for covered water users in the Basin – equipment efficiency upgrades – was also reviewed by the APM Analysis Team. This class of actions, however, was not considered to be an APM since implementing energy efficiency upgrades would not result in a reduction to a covered water user's *per-unit* cost of power. Nevertheless, this topic is discussed in Chapter 17 since the AWIA does reference energy efficiency upgrades as a potential means to reduce *overall* power costs to covered water users in the Basin.

Table ES-1. List of Affordable Power Measures

APM No.	Affordable Power Measure
1	Alternative 1 – Development of Individual Customer Solar PV Generation Facilities
1	Alternative 2 – Development of Shared/Community Solar PV Generation Facilities
1	Alternative 3 – Development Utility/Grid Scale Solar PV Generation Facilities
2	Net Metering Programs (Used in conjunction with other APMs)
3	Out-of-Basin Renewable Energy Investment
4	Time-of-Use Power Rates
5	Irrigation Load-Control Programs
6	Small Hydroelectric Generating Plant Development
7	Purchases of Federal Power
8	Open Access Power Purchases
9	PacifiCorp Irrigation Customer Cost-of-Service Evaluation

The nine APMs are discussed in detail in Chapters 7 – 16 of this Report. Information regarding each APM is organized and presented in a standard format that allows for direct comparison of several key attributes between each of the individual Measures. The standard format consists of sub-chapters that: 1) provide an overview/general description, 2) identify potential benefits, 3) identify potential challenges, and 4) evaluate anticipated net power cost savings. In addition, some APM descriptions contain additional informational sub-chapters (for example, siting considerations).

It should be noted that the nine identified APMs are not necessarily mutually exclusive. In other words, two or more APMs can, in many cases, be concurrently implemented in multiple different combinations by either Reclamation, individual irrigation districts or on-farm covered water users to maximize a given water user's overall power cost savings.[5]

[5] Some combinations of the APMs, however, cannot be implemented on a concurrent basis. For example, PacifiCorp irrigation customers located in Oregon can opt to take service under PacifiCorp's Irrigation Time-of-Use Rate (APM No. 4) or the Irrigation Load Control Rate (APM No. 5), however customers cannot participate in both rate programs at the same time.

APM Implementation Summary

The nine identified APMs cover a broad range of potential mechanisms that can be implemented to help reduce power costs for water users in the Upper Klamath Basin. An important feature of this suite of cost-reduction measures is that many of the APMs can be implemented in a concurrent fashion or in different combinations that best fit the needs of individual water users. While it is true that some of the APMs may not be available or provide an equal level of benefits to all covered water users in the Basin, the APM Analysis Team attempted to identify and evaluate the APMs so that Reclamation, irrigation districts, and individual covered water users would all have multiple viable power cost alternatives available for consideration.

An important feature of the identified APMs is the question of who can actually implement the measures. For example, some of the APMs would either need to be, or could be, implemented by Reclamation, with the associated power cost reduction benefits flowing to individual On-Project covered users via lower operation and maintenance charges. In other cases, individual On-Project and Off-Project covered users could choose, on their own, to implement one or more APM's with the associated benefits accruing solely to themselves.

Table ES-2 summarizes the nine APMs along with information regarding how the measures could be implemented.

High Priority Affordable Power Measures

Based on an appraisal level evaluation of each APM, six Measures were identified as exhibiting the best balance between: 1) a reasonable expectation of meaningful power cost reductions, 2) the ability to implement the Measure in a realistic timeframe, and 3) a widespread distribution of benefits across multiple categories of water users in the Basin. These High Priority Measures are listed in Table ES-3. Insofar as these High Priority Measures have an increased potential to achieve power cost reductions among all the measures considered, where noted in the third column in Table ES-3, Reclamation advocates for further detailed investigation beyond the appraisal level.

Table ES-2. APM Implementation Summary

APM No.	Affordable Power Measure	Who Implements the Measure	How is the Measure Implemented?	Time Horizon for Implementation	Distribution of Benefits
1	Solar PV Development Alternative 1 - (small facilities)	Individual power customer	Individual customer installs solar PV facility	Weeks to months	Individual water user or groups of water users
1	Solar PV Development Alternative 2 – (shared facilities)	Groups of power customers under a central coordinating entity	Individual power customer decision with central entity installing solar PV facility	12 – 24 months	Groups of Off-Project or On-Project water users
1	Solar PV Development Alternative 3 – (grid scale facilities)	A central developer and a central benefits administrator	Developer commits to develop solar PV facility	24-36 Months	Developer enters arrangement with group(s) of water users
2	Net Metering	Individual power customers	Customer signs up with PacifiCorp	1-2 Months	Individual water users who have self-generation
3	Out-of-Basin Renewable Investment	A central developer and a central benefits administrator	Developer commits to invest in a renewable energy project	24-36 Months	Developer enters arrangement with group(s) of water users
4	Time-of-use Power Rates	Individual power customers	Customer signs up with PacifiCorp	TBD based on post-pilot	Individual water user or groups of

APM No.	Affordable Power Measure	Who Implements the Measure	How is the Measure Implemented?	Time Horizon for Implementation	Distribution of Benefits
				program terms and conditions	On-Project water users
5	Irrigation Load Control Programs	Individual power customers	Customer signs up with PacifiCorp	TBD based on post-pilot program terms and conditions	Individual water users or groups of On-Project water users
6	Small Hydro Plant Development	Reclamation or irrigation districts	Developer commits to construct hydro facility	3-5 Years	On-Project water users
7	Purchases of Federal Power	Reclamation	Reclamation develops a new Federal power supply portfolio	2-5 Year	On-Project water users
8	Open-access Power Purchases	Individual power customers	Customer signs up with PacifiCorp and commits to an alternative power supply	Months	Individual water users
9	PacifiCorp Irrigation Cost of Service Evaluation	Individual or group(s) of power customers	Active participation in PacifiCorp rate setting processes in OR and CA	Ongoing with initial action in months	All water users

Table ES-3. High Priority Affordable Power Measures

APM No.	Affordable Power Measure	Federal Study Potential
1	Solar PV Development – Alternative 1 (individual facilities)	Yes
1	Solar PV Development – Alternative 2 (shared/community-scale)	Yes
1	Solar PV Development – Alternative 3 (grid-Scale)	Yes
2	Net Metering (used in conjunction with Solar PV Alternatives 1 & 2)	NA
4	Time-of-Use Power Rates	Note 1
5	Irrigation Load-Control Programs	Note 1
6	PacifiCorp Irrigation Cost-of-Service Evaluation	No

Note 1: To the extent that implementation of these APMs by Reclamation or irrigation districts causes negative impacts to other water users in the Upper Klamath Basin, Federal Funding might be utilized to either: 1) provide financial offsets to the affected users, or 2) develop additional water system infrastructure to directly reduce negative water delivery/timing impacts.

Risk and Uncertainties

Chapter 18 of this Report summarizes several of the more prominent risks and uncertainties associated with the future cost of power for irrigation and drainage in the Upper Klamath Basin along with potential risks in implementing the identified APMs. In addition, some initial observations regarding how such risks might be managed or at least partially mitigated by Reclamation, irrigation districts, and individual water users in the Upper Klamath Basin are discussed as well.

Examples of some of the more prominent risks and uncertainties that could have an impact on the future cost of power in the Basin, or might affect the cost/benefit results of one or more of the APMs are as follows:

- PacifiCorp retail electric tariff price risk
- PacifiCorp retail electric tariff structure risk
- Changes in the Oregon and California net metering programs
- Changes in Federal or State tax incentives

- Changes in Federal import tariffs and policies
- Changes in long-term interest rates
- Changes in region, state, or local land-use/water-use policies

Recommendations/Next Steps

The Power Cost Benchmark Analysis that accompanies this Report concluded that the average per-unit cost of power for irrigation and drainage use in the Upper Klamath Basin during calendar years 2017 – 2018 was approximately 113.2% higher than the costs paid by agricultural water users located in five Reclamation Projects in the Pacific Northwest region that were determined to be similarly situated to the Klamath Project.[6] The Affordable Power Measures that have been evaluated and discussed in this Report - and especially those Measures identified as High Priority Measures – are designed to assist water users (including Reclamation, irrigation districts, and individual covered water users) in reducing their respective power costs via a multi-prong approach.

In developing the final list of High Priority APM's, an emphasis was placed on those Measures that could be implemented in a reasonably short period of time so as to present water users with viable power savings options that they could consider enacting in the near-future, either on an individual customer basis or, in some cases, as part of a group. In addition, Measures implemented by Reclamation or irrigation districts will provide benefits to multiple individual water users.

Consistent with the directives contained in the AWIA and the results of the companion PCB Report that indicates that the average per-unit cost of electric for agricultural water users in the Upper Klamath Basin during 2017 – 2018 was 113.2% higher than the per-unit costs for water users located in five similar Pacific Northwest irrigation Projects,[7] Reclamation recommends that the following actions be undertaken:

Action Item No. 1

Reclamation should immediately move forward to conduct next-step, full feasibility analyses for all of the high priority APMs identified in Table ES-3 of this Report, with the results of these analyses to be shared with irrigation districts and water users located in the Upper Klamath Basin as part of Action Item No. 3.

Action Item No. 2

Reclamation, irrigation districts, and water-user groups should immediately move to jointly sponsor the development of one or more analytical tools that can be used by individual water users in the Basin to perform customized cost/benefits analyses for potential installation of self-generation systems. These tools would be open-sourced, for example utilizing Microsoft Excel, and would be designed to incorporate the: 1) unique aspects of highly seasonal irrigation/drainage loads, and 2) the specific details of the Oregon and California net metering programs. The APM Analysis Team believes that such tools could be developed relatively quickly and in a cost-efficient manner using existing models already developed by the Team as a starting point.

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[6] PCB Report, Chapter 13.

[7] The five Reclamation irrigation projects that were considered to be similarly situated to the Klamath Project (a/k/a the "Similar Projects") are Boise, Columbia Basin, Minidoka, Owyhee, and Yakima.

Action Item No. 3

Reclamation, in conjunction with existing or new water user groups in the Upper Klamath Basin should immediately form a committee (or alternatively utilize an existing committee or organization) that is specifically tasked with developing detailed plans to implement the identified high priority APMs. It is envisioned that this committee/organization would: 1) act as a "one-stop" source of resources and information in the Upper Klamath Basin for Reclamation, irrigation districts, and individual covered users, 2) would assist individual entities in implementing the suite of APMs that best meet the needs of the individual water/power users, and 3) would act as a liaison with state and local land-use or water-use planning bodies regarding how the implementation of certain APMs could be achieved under established planning policies.

This central committee/organization would also be a primary contact point with other entities that can provide assistance to water users in implementing the APMs such as equipment providers (including Solar PV installers), potential sources of funding (such as the Energy Trust of Oregon), and entities that can assist water-users in performing customized APM cost-benefit analyses. In addition, this committee/organization would provide a forum for Reclamation to share the results, and receive feedback on, the APM feasibility analyses to be conducted under Action Item No. 1.

Action Item No. 4

Reclamation, in conjunction with existing and new water user groups in the Upper Klamath Basin, should immediately form a committee whose primary focus is to advocate for agricultural power customers in the Basin at the Oregon and California Rate Commissions. In particular, such a committee would be actively involved in PacifiCorp general rate cases and power cost adjustments cases, along with providing input in various state-level decision making processes involving net metering policies, PacifiCorp's Long-Term Integrated Resource Plans, greenhouse gas reduction policies, potential PacifiCorp electric tariff re-structuring, and other related issues that could potentially impact (either positively or negatively) the overall cost of power for irrigation/drainage users in the Basin.

Chapter 1 Purpose and Scope

This Affordable Power Measures ("APM") Analysis and Report has been prepared by the United States Bureau of Reclamation ("Reclamation") as the Secretary of the Interior's (Secretary's) response to certain provisions outlined in the America's Water Infrastructure Act of 2018 (Pub. L. 115-270, "AWIA") regarding the reduction of power costs to agricultural water users in the Upper Klamath Basin. Specifically, Section 4308 of the AWIA amended the Klamath Basin Water Supply Enhancement Act of 2000 (Pub. L. 106-498) to address power and water management in the Klamath Basin, including reduction of power costs (Enhancement Act as amended, Section 4(c)). The Enhancement Act as amended will hereafter be referred to as the "Enhancement Act."

The AWIA amended the Enhancement Act by inserting a new Section 4 into the Enhancement Act as follows (portions of the amendment not pertaining to reduction of power costs are omitted for clarity):

SEC. 4. POWER AND WATER MANAGEMENT.
(1) COVERED POWER USE.—The term 'covered power use' means a use of power to develop or manage water from any source for irrigation, wildlife purposes, or drainage on land that is—

(A) associated with the Klamath Project, including land within a unit of the National Wildlife Refuge System

that receives water due to the operation of Klamath Project facilities; or

(B) irrigated by the class of users covered by the agreement dated April 30, 1956, between the California-

Oregon Power Company and Klamath Basin Water Users Protective Association and within the Off Project Area (as defined in the Upper Basin Comprehensive Agreement entered into on April 18, 2014), only if each applicable owner and holder of a possessory interest of the land is a party to that agreement (or a successor agreement that the Secretary determines provides a comparable benefit to the United States).

(3) POWER COST BENCHMARK.—The term 'power cost benchmark' means the average net delivered cost of power for irrigation and drainage at Reclamation projects in the area surrounding the Klamath Project that are similarly situated to the Klamath Project, including Reclamation projects that—

(A) are located in the Pacific Northwest; and

(B) receive project-use power.

(c) REDUCING POWER COSTS.—

(1) IN GENERAL.—Not later than 180 days after the date of enactment of America's Water Infrastructure Act of 2018, the Secretary, in consultation with interested irrigation interests that are eligible for covered power use and organizations representative of those interests, shall submit to the Committee on Energy and Natural Resources of the Senate and the Committee on Natural Resources of the House of Representatives

a report that—

(A) identifies the power cost benchmark; and

(B) recommends actions (other than direct payments to persons making covered power uses or to other entities for the purposes of subsidizing power rates) that, in the judgment of the Secretary, are necessary and appropriate to ensure that the net delivered power cost for covered power use is equal to or less than the power cost benchmark, including a description of—

(i) actions—

(I) to immediately reduce power costs; and

(II) to ensure that the net delivered power cost for covered power use is equal to, or less than, the power cost benchmark in the near term, while longer-term actions are being implemented;

(ii) actions that prioritize—

(I) water and power conservation and efficiency measures that could assist in achieving the power cost benchmark;

(II) to the extent actions involving the development or acquisition of power generation are included, renewable energy technologies (including hydropower); and

(III) regional economic development;

(iii) the potential costs and timeline for the actions recommended under this subparagraph;

(iv) provisions for modifying the actions and timeline to adapt to new information or circumstances;

and

(v) a description of public input regarding the proposed actions, including—

(I) input from water users that have covered power use; and

(II) the degree to which those water users concur with the recommendations.

In satisfaction of these requirements, this APM Report is being submitted to the Committee on Energy and Natural Resources of the U.S. Senate and the Committee on Natural Resources of the U.S. House of Representatives (collectively "the Committees"). A separate companion report -

referred to as the Power Cost Benchmark ("PCB") Report - is also being submitted to the Committees as directed by the Enhancement Act.

Affordable Power Measures

The set of specific actions that have been developed in response to the criteria referenced above are referred to in this report as "Affordable Power Measures" or "APMs". APMs are defined as actions that can be undertaken by stakeholders/water users to reduce power costs for irrigation and drainage use in the Upper Klamath Basin to a level equal to or below the Power Cost Benchmark.[8] The methodologies utilized to identify, evaluate, and select the final set of recommended APMs are described in various chapters of this Report.

Prior Power Cost Reduction Studies for the Klamath Project

Prior to the passage of the AWIA, Reclamation conducted an analysis of power costs in the Upper Klamath Basin which was released as part of the Klamath Comprehensive Agricultural Power Plan ("CAPP") in February 2016. The CAPP Report presented a set of alternatives that might be implemented in order to reduce power costs to agricultural water users located in the Basin. This APM Report updates, and in several areas significantly expands upon, this earlier analysis with the goal of identifying a set of APMs to help reduce the net delivered cost of power[9] for covered power use[10] in the Upper Klamath Basin.

The APM Analysis Team

The completion of the APM Analysis and the accompanying Report was a group effort that involved multiple individuals from several organizations including Reclamation's Klamath Falls regional office, the Klamath Water Users Association ("KWUA") through its power committee in which other Upper Klamath Basin irrigation interests were invited to participate, and Kleinschmidt Associates.[11] Collectively, this group is referred to throughout this Report as the "APM Analysis Team" or "the Team." Appendix A contains a list of the individuals who were part of the APM Analysis Team and the organizations with which they are affiliated.

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[8] As is described in more detail in the accompanying Power Cost Benchmark Report, the PCB is a per-unit measure (expressed in terms of ¢/kilowatt-hour) of the cost of power for irrigation and drainage use in Reclamation Projects located in the Pacific Northwest Region and that are similarly situated to the Klamath Project.

[9] The term "net delivered cost of power" is used in Section 4(a)(3) of the AWIA when defining the Power Cost Benchmark.

[10] The term "covered power use" for the Klamath Basin is defined in Section 4(a)(1) of the AWIA.

[11] Reclamation retained Kleinschmidt Associates to provide consulting services for the APM and PCB analyses pursuant to Contract #140R2019F0015 AWIA Klamath Power Studies.

Chapter 2 Description of the Klamath Project

Overview

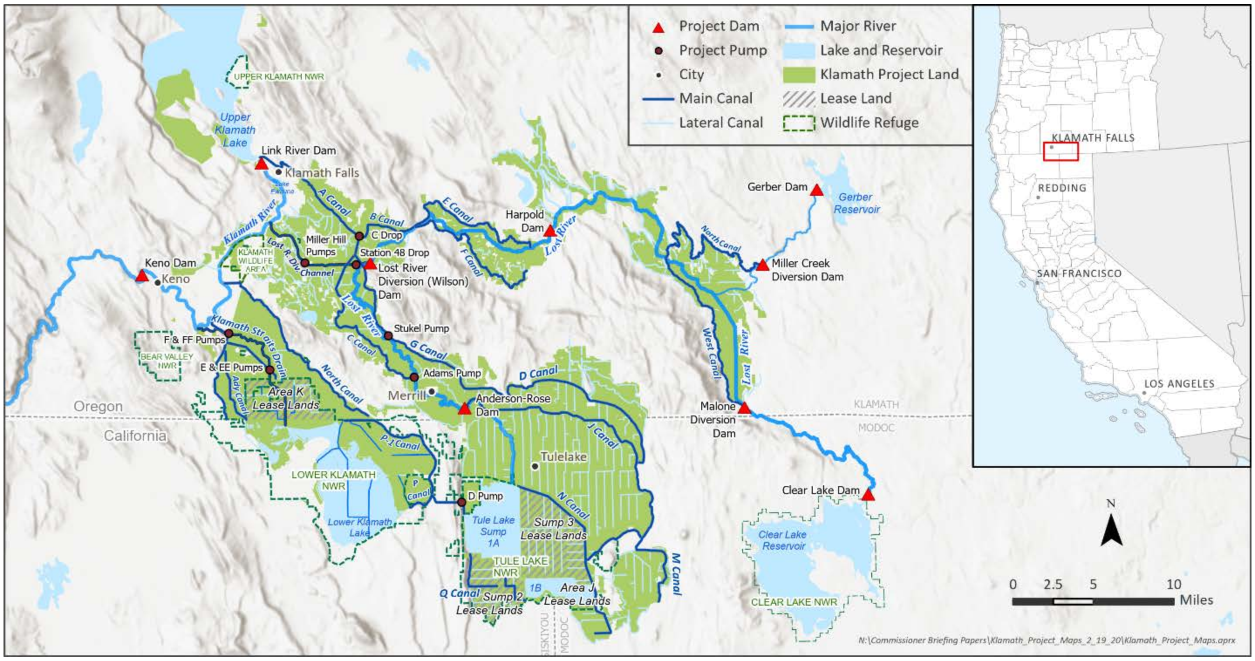
The Secretary of the Interior authorized development of the Klamath Project on May 15, 1905, under provisions of the Reclamation Act of 1902 (32 Stat. 388). The irrigable lands of the Klamath Project are in south-central Oregon (62 percent) and north-central California (38 percent) and cover lands in Klamath County, Oregon, and Siskiyou and Modoc counties in northern California. In addition to providing water that supports the Tule Lake National Wildlife Refuge and the Lower Klamath National Wildlife Refuge, the Project provides full-service water to approximately 210,000 acres of cropland and rangeland located within the Upper Klamath Basin.

The Upper Klamath Basin has extensive land and water resources which are not fully developed. The terrain varies from rugged, heavily timbered mountain slopes to rolling sagebrush bench lands and broad, flat valleys. The Project plan includes construction of facilities to divert and distribute water for irrigation of basin lands, including reclamation of Tule and Lower Klamath Lakes, and control of floods in the area.

The two main sources of water for the Project are: 1) Upper Klamath Lake and the Klamath River; and 2) Clear Lake Reservoir, Gerber Reservoir, and Lost River, which are in a closed basin. The total drainage area, including the Lost River and the Klamath River watershed above Keno, Oregon, is approximately 5,700 square miles. Principal irrigated crops within the Project include: alfalfa hay and grass hay, irrigated pasture, grains, potatoes, and onions, with smaller acreage in mint and horseradish.

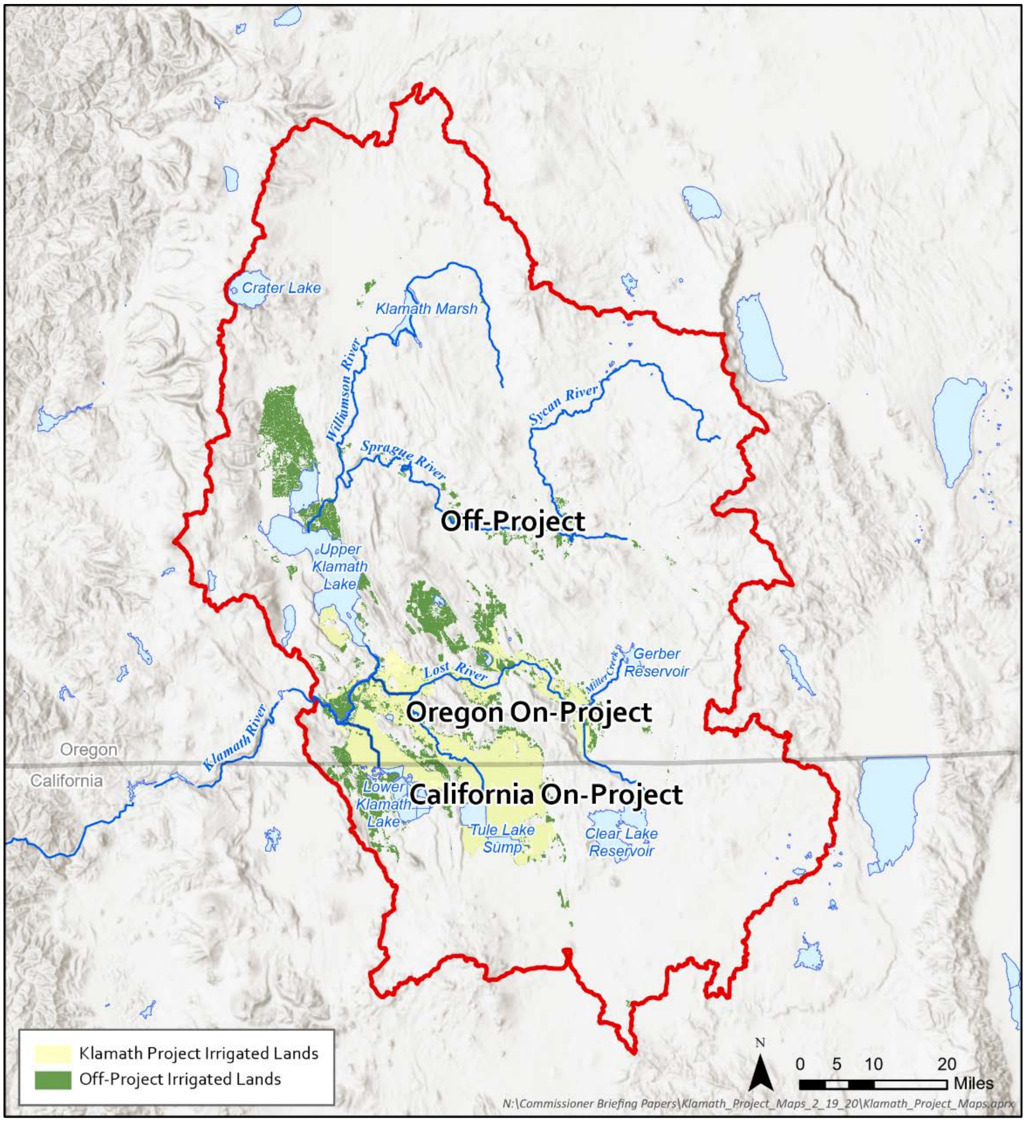
Beyond the ecosystem benefits that are provided and irrigation customers that are served by the Project, there are a significant number of additional water users irrigating lands that are located within the larger Upper Klamath Basin. These so-called "Off-Project areas" include irrigated lands in Oregon within the watersheds of the Lost, Sprague, Williamson, and Wood rivers. Figure 2-2 below shows the boundaries of the Off-Project areas located within the Upper Klamath Basin (outlined in red) and how these areas relate to the Project's boundaries.

Figure 2-1. Klamath Irrigation Project



Klamath Project Area

Figure 2-2. Upper Klamath Basin Off-Project Areas



Upper Klamath Basin Off-Project Areas

For the purposes of the APM Report (and the accompanying PCB Report as well), there are water uses located in the Off-Project areas that are considered to be "covered users" under the AWIA.[12] Therefore, this APM analysis incorporates power cost information for irrigation and/or drainage customers that are located both within the Klamath Project's boundaries and the covered users that are located in the Upper Klamath Basin Off-Project areas.

Several of the key elements and characteristics of the Klamath Project are summarized in Table 2-1 below.

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12 See AWIA Section 4308, Sec 4(a)(1).

Table 2-1. Project Elements and Characteristics

Project Elements	Data
Irrigated acres	191,592 – 230,769 acres*
Average annual precipitation	13.8 in
Mean temperature	49 F
Growing season	120 days
Elevation of irrigable areas	4,093 ft
Project authorization	1905
Storage Dams	3
Diversion Dams	4
Canals	185 mi[13]
Laterals	532 mi
Pumping Plants	28
Drains	728.2 mi
Tunnels	1.9 mi

Source: Reclamation website https://www.usbr.gov/projects/index.php?id=470
*191,592 figure is from Reclamation project website; 230,769 from GIS data

What is not reflected in Figure 2-1, however, is the complexity of the system's actual operation which includes a network of gravity fed canals, along with significant electrical loads associated with numerous pumps in the system that must lift water where elevation changes must be overcome or where drainage must occur. In particular, the Klamath Project is unique in that very little pumping is required to initially deliver water into the upstream portions of the Project, however significant amounts of pumping are required to lift water out of the downstream portions of the Project (which are located in a closed basin) in order to recirculate and reuse water and provide return flows back into the Klamath River. The system is often noted as one of the more complex "plumbing" efforts for irrigated lands served by Reclamation water.

[13] The figures shown for canals, laterals, pumping plants and drains excludes facilities located within the Project area that are owned by non-Federal entities.

Chapter 3 Historical Power Costs for Irrigation and Drainage in the Upper Klamath Basin

Overview and Historical Context

At the time of the Klamath Project's development, Reclamation filed for all unappropriated water in the Klamath Basin along with the right to appropriate water for power development at several locations. Reclamation recognized that in order to irrigate the land it was necessary to access power for both drainage and pumping purposes. Although Reclamation had the authority and intent to develop and provide power to the Klamath Project irrigators at the time of the Project's development, inadequate funding in the early years of development had prevented it from doing so.

In 1916 the California Oregon Power Company ("COPCO"), now PacifiCorp, approached Reclamation and proposed building a dam on Upper Klamath Lake to provide better water regulation for COPCO's existing and planned hydropower facilities to be developed on the Klamath River. In 1917, Reclamation entered into a 50-year contract with COPCO for the construction and operation of Link River Dam that also included provisions for COPCO to provide power at discounted rates to the Klamath Project beneficiaries. Reclamation's contract with COPCO protected irrigation rights and provided the Klamath Project water users with power rates locked in at 1917 levels; this agreement therefore allowed Reclamation to provide the Klamath Project with power for Basin irrigators as was its original intent.

The original COPCO/Reclamation contract was amended in 1956, featuring essentially the same power rates for an additional 50-year period. This agreement was a condition of PacifiCorp's Klamath Hydroelectric Project FERC operating license becoming effective. Later in 1956, a separate COPCO contract provided Off-Project agricultural power users located in the Upper Klamath Basin with reduced power rates similar to those of the On-Project users.

At the expiration of PacifiCorp's FERC license in 2006, Reclamation and the Upper Klamath Basin irrigation community appealed to FERC and the Oregon Public Utility Commission ("OPUC") and the California Public Utility Commission ("CPUC")[14] to preserve the reduced power rate agreements provided for in the 1956 FERC license, initially in connection with the automatic one-year renewals of the license. Despite these appeals, FERC and the PUCs ultimately did not compel PacifiCorp to continue to provide power at reduced costs and allowed PacifiCorp to phase in full tariff rates over a period of several years. The 1956 contract expiration and FERC and the PUCs ruling ended nearly 90 years of reduced or at-cost power rates for Upper Klamath Basin irrigators.

[14] Collectively, the OPUC and the CPUC are referred to in this Report as "the Rate Commissions", "the Commissions", or "the PUCs".

Current Conditions

The termination of the 1956 PacifiCorp power supply agreements resulted in an increase in power rates for agricultural water users in the Klamath Basin from 0.3 to 0.75 cents per kilowatt-hour (¢/kWh) in 2006 to approximately 11.1 ¢/kWh in Oregon and 15.2 ¢/kWh in California during 2017 - 2018. With these changes, the average water pumping cost on the Klamath Project in 2015 was $45 per acre as compared to an average power cost of $2.25 per acre prior to the 1956 power contract's expiration.

It is important to note that the 1956 power contracts in place with PacifiCorp up until 2006 were unique in that low-cost power supplies were made available not only to the Klamath Project itself,[15] but also to districts for their own pumps, and individual On-Project and Off-Project irrigation customers as well. Therefore, the expiration of these agreements in 2006 and the subsequent phase-in to PacifiCorp's full retail tariff rates had a double (or triple) impact of not only significantly increasing costs at federal pumps delivering water supplies (and drainage) to ultimate On-Project users but also in increasing these same water users' individual at-site water distribution costs, and those of their irrigation districts as well. Off-Project water users also endured significantly higher costs by virtue of having to purchase all their on-farm power supply needs from PacifiCorp under full retail tariff rates.

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[15] In this regard, the 1917 and 1956 power contracts between Reclamation and PacifiCorp were akin to Federal Project-use Power arrangements that were historically established at multiple Reclamation irrigation projects located throughout the Pacific Northwest Region (and that remain in place today).

Chapter 4 The Comprehensive Agricultural Power Plan Report

Overview

In October 2016, Reclamation publicly released the Comprehensive Agricultural Power Plan ("CAPP") Report for the Klamath Basin. The CAPP was an extensive effort initiated by Reclamation and multiple stakeholders to identify, discuss, and screen multiple different alternatives that might help lower overall power costs for both On-Project and Off-Project covered irrigation water users located in the Oregon and California portions of the Upper Klamath Basin.

The CAPP was also initiated in the context of a broader effort to assess many different facets of water use in the Klamath Basin; this process resulted in the Klamath Basin Restoration Agreement ("KBRA") which was finalized by Reclamation and multiple stakeholders in 2010. The KBRA sought to address short-, medium, and long-term power costs in the Upper Klamath Basin in light of the PacifiCorp power contracts. As part of the development of the CAPP, Reclamation worked with PacifiCorp to assemble historical power usage information for the Upper Klamath Basin On-Project and Off-Project water users; some of this information was utilized by the APM and PCB Analyses Teams in deriving the usage-weighted average power cost in the Basin during calendar years 2017 and 2018. [16]A complete copy of the 2016 CAPP Report is available via the web-site link listed in Appendix F of the Report.

CAPP Power Cost Savings Measures

The CAPP Report contains several sections that provide background and context on irrigation water use in the Upper Klamath Basin and the history associated with the original 1917 and the subsequent 1956 PacifiCorp power supply contracts that were in place with Reclamation and KWUA on behalf of other water users in the Upper Klamath Basin. The Report describes in detail a total of eighteen potential power cost savings measures ("Measures") that were identified by the CAPP Analysis Group. Pre-feasibility study-level economic analyses were performed on all the identified Measures.

Once the universe of potential power cost savings Measures were identified and various analyses performed, all of the Measures were screened and ranked using nine different criteria including forecasted reductions in power rates, administrative intensity, access to benefits, and environmental impacts.[17] Rankings in each area were on a four step scale with "Excellent/Yes" being the highest ranking and "Poor/No" being the lowest ranking. Overall scores for each Measure were then

[16] These computations are discussed in more detail in Chapter 10 of the accompanying PCB Report.
[17] The complete list of the power cost savings measures screening criteria and the associated results are described in Section 5 of the CAPP Report.

derived (across all nine of the individual scoring criteria) and the overall results were then arranged into the following three tiers:

- Tier-1 – Measures that present the best opportunities to lower power rates.
- Tier-2 – Measure that have promise to lower power rates but that may contain implementation obstacles or provide a lower potential for reducing power rates than Tier-1 Measures.
- Tier-3 – Measures that do not reduce power rates or contain substantial uncertainties.

It should be noted that the CAPP Study and the accompanying report were completed prior to the enactment of the AWIA. However, the twelve Tier-1 and Tier-2 power cost savings Measures that were originally identified in the CAPP and that were selected for further consideration as part of the APM Analysis are all consistent with the AWIA's provisions regarding the Upper Klamath Basin.[18]

[18] Additional details regarding the complete universe of potential power cost savings measures that were considered as part of the APM analysis are contained in Chapter 6.

Chapter 5 APM Report Public/Stakeholder Process

Overview

An important component of the APM analysis was the inclusion of interested stakeholders in the study process who provided meaningful input into the production of the final APM Report. In particular, many stakeholders have long histories of living and working in the Upper Klamath Basin and their informed insights on the impacts of higher electricity prices on irrigation practices in the Basin were invaluable to the APM Analysis Team.

Interested stakeholders had several different avenues available in which to stay informed of and/or provide input to the APM analysis throughout the life of the project, including the following:

- Regular bi-weekly APM project status conference calls with Reclamation and the APM Analysis Team.
- A project kickoff meeting with Reclamation and the APM Analysis Team on March 19, 2019.
- A focused progress review session with Reclamation and the APM Analysis Team on June 11, 2019.
- A public meeting held in Klamath Falls on September 10, 2019.
- An opportunity to review and provide written comments on the Draft APM Report that was made available to the public on November 18, 2019. Interested parties were invited to submit comments to Reclamation by December 2, 2019.

Upper Klamath Basin Stakeholder Public Meeting

On September 10, 2019, the APM Analysis Team jointly hosted a public meeting in Klamath Falls, Oregon to present general information regarding the APM (and PCB) topics and to provide and discuss some of the preliminary findings. Approximately 65 persons attended the meeting and many of those present were actively engaged in asking questions of the APM Analysis Team and providing constructive feedback. Additionally, several local organizations that assist consumers in lowering or more efficiently managing their energy costs attended the meeting and made short presentations regarding the services they can provide to agricultural water users in the Upper Klamath Basin.

A more detailed synopsis of the September 10 public stakeholder meeting is contained in Appendix B.

Draft APM Report Public Comments

As noted above, Reclamation posted a draft version of the APM Report on its website for public comment on November 18, 2019 with comments due by December 2, 2019.[19] Written comments regarding the draft APM Report were submitted to Reclamation by the following organizations/persons:

1. Mr. Duval (private citizen)
2. Mr. Gierak (private citizen)
3. Klamath Water Users Association
4. Mr. Pace (private citizen)
5. WaterWatch

Reclamation appreciates the effort made by stakeholders in submitting comments regarding the draft APM Report. All comments received by the submittal deadline were reviewed by Reclamation and the APM Analysis Team and appropriate revisions and updates were made throughout this Final PCB Report in response to the input received from stakeholders.

A summary of all the comments received from stakeholders regarding the draft APM Report is contained in Appendix C.

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[19] Prior to posting the draft APM Report on its website, Reclamation issued a press release on November 8, 2019 so that interested stakeholders would be informed of: 1) the opportunity to provide comments on the Report, and 2) the due date for submitting comments to Reclamation. Due to technical difficulties encountered by Reclamation in its initial posting of the draft APM Report on November 8, 2019, Reclamation subsequently re-posted a corrected version of the Report on November 18, 2019 and extended the comment deadline to December 2, 2019.

Chapter 6 Identifying the Affordable Power Measures

Overview

The 2016 CAPP Report contained a significant amount of detail on 18 potential alternatives for reducing power costs to the Klamath Project and to individual on-farm covered water users located in the Upper Klamath Basin. These alternatives were subjected to a rigorous screening process and then ranked into three separate tiers based upon a combination of factors including economics, environmental impacts, potential regulatory issues, and consistency with the KBRA.

In initially defining the broad parameters for the APM Analysis, the APM Analysis Team agreed that the Analysis should utilize the earlier work originally developed for the CAPP as a starting point in order to re-assess and identify viable APMs for the Upper Klamath Basin pursuant to the directives specified in the Enhancement Act. To this end, the Team first reviewed the results from the CAPP Report and developed a list of power cost savings measures to potentially be considered as part of the APM Analysis. Following this initial screening process, the Team choose 12 power cost savings alternatives from the CAPP to be considered as potential affordable power measures in the APM Analysis.[20]

Following multiple rounds of open discussion and preliminary evaluations, the Team then identified several additional cost-savings measures for consideration under the APM Analysis that were not previously analyzed as part of the CAPP study. From the overall list of potential APM candidates, the Team then performed a high-level screening process that resulted in a final list of nine Affordable Power Measures to be evaluated in more detail.[21] In developing the final list of nine potential power cost savings measures, the Team placed a focus on Measures that were judged to be: 1) consistent with the requirements established in the Enhancement Act,[22] 2) economically viable given current and forecasted conditions, 3) consistent with the existing regulatory frameworks in

[20] All 12 of the power cost savings alternatives from the CAPP that were selected to be included in the APM Analysis were ranked as either Tier-1 or Tier-2 alternatives under the CAPP's screening process.

[21] One additional means for potentially reducing power costs for covered water users in the Basin – equipment efficiency upgrades – was also reviewed by the APM Analysis Team. This class of actions, however, was not considered to be an APM since implementing energy efficiency upgrades would not result in a reduction to a covered water user's *per-unit* cost of power. Nevertheless, this topic is discussed in Chapter 17 since the AWIA does reference energy efficiency upgrades as a potential means to reduce *overall* power costs to covered water users in the Basin.

[22] For example, the potential development of new generating plants to help reduce power costs in the Upper Klamath Basin was limited to renewable resources (such as hydro, wind and solar) as specified in the AWIA. This requirement resulted in several CAPP Study Tier-1 and Tier-1 power cost reduction alternatives (including the development of new natural-gas fired generating facilities or the conversion of electric pumps to natural gas) being dropped from consideration as potential Affordable Power Measures in the APM Analysis.

place in Oregon and California, 4) have minimal environmental impacts, and 5) are realistically implementable.

The APM Analysis Group recognized that the potential benefits to be derived from some of the identified power cost savings measures might not be equally distributed across all covered water users in the Upper Klamath Basin due to a variety of factors including different state utility Rate Commissions, differences in state regulatory and environmental processes, differences between On-Project and Off-Project covered water users, and the unique characteristics of the Measures themselves. However, in screening the various candidate Measures, the APM Analysis Team attempted to craft a package of recommended Measures that - when taken as a whole – is expected to create power cost reduction benefits to Reclamation, the irrigation districts located within the Klamath Project, and both On-Project and Off-Project covered water users in the Upper Klamath Basin.

Summary of the Affordable Power Measures

The final list of nine power cost savings measures was chosen by the APM Analysis Team from a combination of: 1) Measures previously identified in the CAPP Report as being the most promising alternatives, and 2) Additional Measures as identified by the Team. Table 6-1 below summarizes the nine Affordable Power Measures for the Upper Klamath Basin.

Each of the individual APMs shown in Table 6-1 is discussed in detail in Chapters 7 through 16 of this Report.

It should be noted that the APMs listed in Table 6-1 are not necessarily mutually exclusive. In other words, two or more APMs can, in many cases, be concurrently implemented in multiple different combinations by either Reclamation, individual irrigation districts or on-farm covered water users to maximize a given water user's overall power cost savings.[23]

Technical details regarding the appraisal level analyses conducted by the APM Analysis Team on the nine identified APMs are contained in Appendix D to this Report.

[23] Some combinations of the APMs, however, cannot be implemented on a concurrent basis. For example, PacifiCorp irrigation customers located in Oregon can opt to take service under PacifiCorp's Irrigation Time-of-Use Rate (APM No. 4) or the Irrigation Load Control Rate (APM No. 5), however customers cannot participate in both rate programs at the same time.

Table 6-1. List of Affordable Power Measures

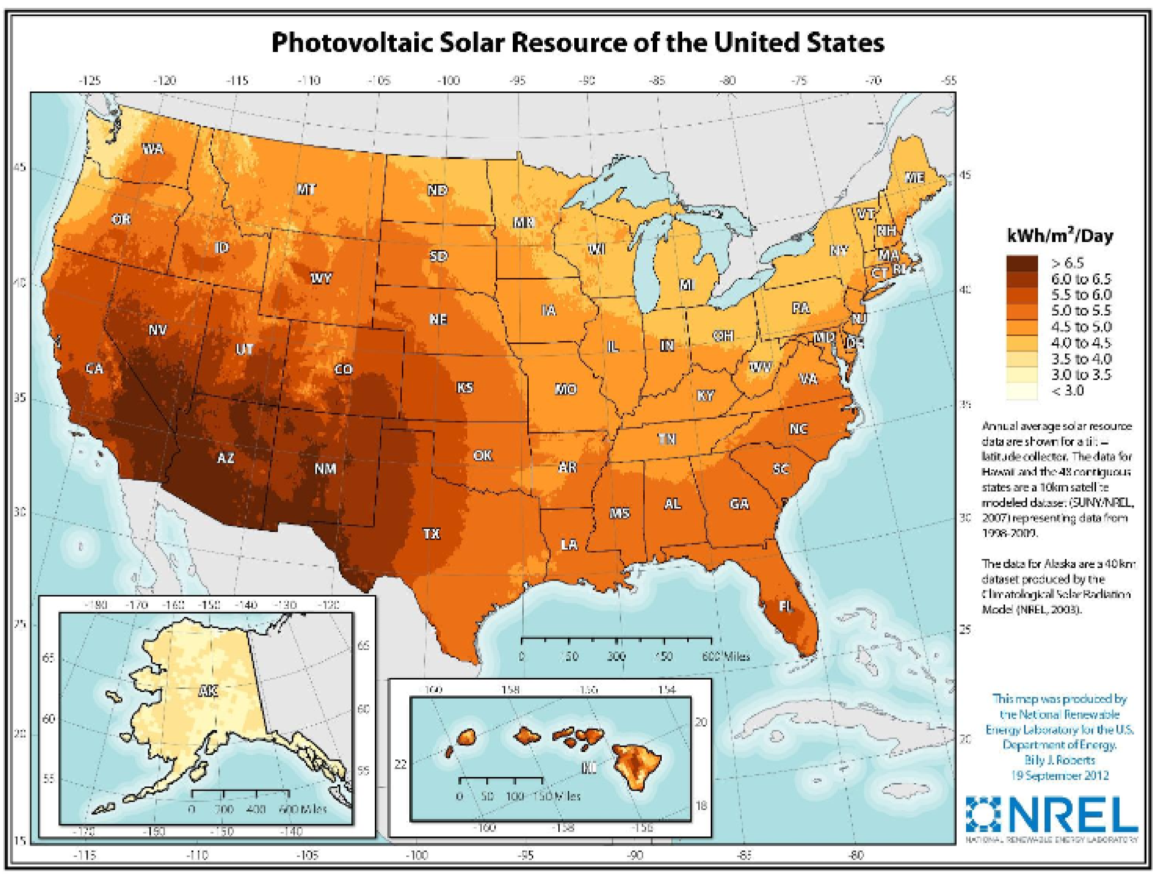
APM No.	Affordable Power Measure
1	Alternative 1 – Development of Individual Customer Solar PV Generation Facilities
1	Alternative 2 – Development of Shared/Community Solar PV Generation Facilities
1	Alternative 3 – Development Utility/Grid Scale Solar PV Generation Facilities
2	Net Metering Programs (Used in conjunction with
3	Out-of-Basin Renewable Energy Investment
4	Time-of-Use Power Rates
5	Irrigation Load-Control Programs
6	Small Hydroelectric Generating Plant Development
7	Purchases of Federal Power
8	Open Access Power Purchases
9	PacifiCorp Irrigation Customer Cost-of-Service

Chapter 7 APM No. 1- Solar Photovoltaic (Multiple Alternatives)

Klamath Basin Solar Photovoltaic Generation Potential

In 2012, the National Renewable Energy Laboratory (NREL) for the United States (U.S.) Department of Energy released a map of photovoltaic (PV) solar resources in the U.S. based on data from 1998 to 2009, as shown in Figure 7-1.

Figure 7-1. Photovoltaic Solar Resources of the United States



The map shown in Figure 7-1 indicates that solar irradiance in the Upper Klamath Basin is well suited for solar PV generation development, with solar intensities ranging from 5.0 to 6.0 kWh per square meter per day[24]. In general, the most ideal sites for solar PV development should meet the following criteria:

<u>Proximity to loads</u>
Can the solar PV generation be used by loads close to the PV array?

<u>Proximity to Transmission/Distribution Infrastructure</u>
If a larger, utility scale project is proposed, is the site close to power transmission or distribution lines, or both?

<u>Site location</u>
Is the site open to the south or southwest without tree cover?

<u>Site geography</u>
Is the site flat or does it slope slightly to the south or southwest?

<u>Local microclimate</u>
Is the site prone to fog or flooding that would limit solar irradiance or flood electrical components? As will be discussed in more detail in the sub-chapters that follow, the desired or optimal site characteristics for solar PV facilities are a function of both size and the intended use of the facility.

Description of Solar PV Alternatives in the Upper Klamath Basin

While solar PV technology has been commercially available in the United States for several decades, capital development costs for solar installations have declined significantly over the past few years, and further significant cost reductions are anticipated. At the same time, the conversion efficiency of the solar panels has also significantly improved over time. The combination of higher efficiencies and lower installation costs means that potential applications of this technology that previously were not economical compared to other power supply alternatives may now be a preferred alternative.

One important benefit of solar PV technology is that while individual solar PV panels are relatively small, they are modular in design and the panels and associated equipment (such as panel racks and DC/AC invertors) can easily be scaled to form generating facilities that vary from small, individual home or farm installations (in the range of 3-5 kW of installed capacity) up to very large, utility grid-scale facilities (that can exceed 200 MW of installed capacity). Another key benefit is the relative flexibility of siting; unlike many other power generation technologies that have very specific siting requirements, solar PV panels can be installed at a wide range of locations.

The overall size and location of a given solar PV generating facility is driven by several different design criteria. Therefore, in evaluating this APM, the APM Analysis Team recognized that different size facilities, and their locations, would likely require tailoring and adaptation to meet different sets of needs. Subsequently the Team defined three different alternatives - representing three specific size ranges of solar PV generating facilities - to be evaluated under this one APM. These three alternatives are:

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[24] The solar intensities shown in Figure 7-1 range from a low of < 3.0 kWh/m2 to a high of > 6.5 kWh/m2.

- Alternative 1 – Small-Scale/Individual customer solar PV facilities
- Alternative 2 – Shared/Community solar PV facilities
- Alternative 3 – Large-Scale/Grid-Scale solar PV facilities

Each of the three solar PV generating alternatives is discussed separately in the following sub-chapters. While there are definitely common characteristics present across all three alternatives, discussing and evaluating each alternative separately provides for a better understanding of how this APM can be targeted to specific needs and circumstances in order to create power cost savings benefits across a wide variety of power users in the Upper Klamath Basin.

As solar PV generating facilities are becoming more commonplace at various scales in the power industry, developers are typically pairing them with energy storage devices such as batteries. In particular, recent cost reductions in large-scale battery storage technologies are allowing combined solar PV/storage facilities to provide energy and capacity to the grid at prices competitive with new natural gas fired generating plants without the limitations traditionally ascribed to solar PV facilities, namely their inability to serve loads when the sun is not shining. Battery storage technology can even be applied at the single-user level via commercially available equipment that allows customers to actively monitor and manage their own power usage patterns. The potential to pair energy storage technology with solar PV generating facilities in the Upper Klamath Basin is discussed for each of the three solar PV alternatives.

Alternative 1 – Small-Scale/Individual Customer Facilities

Overview/General Description

Small-scale solar PV systems with installed capacities of approximately 2 to 100 kW could be privately owned by individual residences, businesses, and agricultural water users. The common attribute of these systems is that they would be "behind the meter" installations that are designed to partially (or potentially fully) offset an individual customer's electrical usage at a specific location. These small PV installations typically have relatively small footprints, could be roof-mounted or ground-mounted, and could utilize either fixed-axis tracking or variable-axis tracking systems.[25]

Several small-scale solar PV facilities designed to provide power to individual loads have been installed in the Basin, for example a 10-kW system that was installed by the Klamath Irrigation District at its main office building in Klamath Falls.

Potential Benefits

The power produced by small-scale solar PV systems directly offsets the energy supplied by the local utility, therefore reducing the individual customer's energy, and in some cases, capacity (i.e. demand) costs. Also, under some situations, the electricity produced by the solar PV facility may exceed the individual customer's overall electrical load on either a short-term (i.e. hour-to-hour) or long-term (monthly to annual) basis. In these cases, the customer is essentially supplying energy in excess to

[25] Variable-axis tracking systems – which can utilize either single-axis or dual-axis configurations - continuously adjust the orientation of the solar panels as the sun moves across the sky in order to increase electrical energy production during the early morning and late afternoon periods.

required needs to the local utility (in this case, PacifiCorp). These concepts – collectively referred to as "net metering" – are discussed in more detail in Chapter 8 (APM No. 2).

Potential Challenges

Small-scale solar PV systems have relatively few constraints since the modular nature of the technology, combined with its portability, results in many potential siting opportunities. However, typical solar PV systems for agricultural pumping purposes are ground-mounted; depending on the system size, some amount of farmland may be required for the installation. For example, a 100-kW system would require approximately one acre for the PV array and power collection system. Also, customers would be responsible for performing regular maintenance functions on their own solar PV equipment (or contracting out for these services).

This option provides benefits only to individual loads attached directly to the small-scale solar PV facility; individual installations have no capability to generate benefits to the covered power users as a group.

Siting Considerations

The primary siting consideration for small-scale solar PV facilities is having available land/space with a generally open southern exposure that is relatively close to the pumping load and the associated electric meter. The physical electrical interconnection process is fairly simple since the raw output from the PV system is low voltage and is wired downstream of the meter. However, as is discussed in more detail below, the per-unit installation costs (measured in $/kW) of small-scale solar systems are highly dependent upon local site conditions.

Energy Storage Options

Small-scale lithium-ion battery storage systems are currently commercially available that could be installed in combination with an individual customer-sized solar PV facility, however such small-scale systems are currently relatively expensive. In addition, under the net metering programs currently in effect in Oregon and California, there is little incentive for individual customers to install small-scale battery storage devices since the net metering accounting process essentially allows a customer to store power "on paper" with PacifiCorp on a 1:1 basis (with some limitations). However, if the Oregon and California net metering programs were to be revised in the future, small scale battery storage facilities may become more economically attractive, especially if battery costs continue to drop along with further technological advances.

Financial Incentives for Small-Scale Solar PV Systems

At the present time, there are significant financial incentives available to owners of small-scale solar PV systems in Oregon and California that can significantly reduce the up-front investment cost of a new facility. The Federal Investment Tax Credit ("ITC") can be utilized to directly off-set a portion of the owners' overall installation cost of new Solar PV system. For 2020, the ITC is set at 26%; however, under current tax law the ITC is scheduled to be reduced to 22% in 2021 and will phase out completely for residential systems in 2022.[26] For a cash-financed solar PV system, the impact of the ITC is to effectively reduce the owner's dollar per kW up-front investment cost in a new Solar PV system by 26%.

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[26] A 10% ITC remains in effect after 2022 for commercial solar PV facilities.

For small solar PV systems to be installed in Oregon, the Energy Trust of Oregon also offers an up-front financial incentive equal to $80 per installed kW that can be combined with ITC incentive. Like the ITC, this incentive is also paid up-front to owners of new small-scale solar PV facilities, which again acts to directly reduce the overall dollar per kW initial investment cost of the facility.

Anticipated Net Power Cost Savings

The primary benefit of individual small-scale solar PV facilities is that they are interconnected behind the customer's electric meter such that generation produced directly offsets the customer's electrical load without incurring any transmission or distribution costs on PacifiCorp's system. Therefore, power cost savings to the customer are maximized and the amount of self-generation produced acts to reduce the customer's energy purchases from PacifiCorp on a kWh-for-kWh basis. This situation allows the customer to avoid paying the PacifiCorp billing charges that are assessed on a per-kwh of electrical usage basis.[27] While this direct off-set/avoided purchase concept is relatively straightforward when applied to residential or commercial electrical loads that are relatively constant throughout the year, different conditions are present for irrigation pumping/drainage loads that tend to be highly seasonal in nature. This important topic is discussed in more detail in Chapter 8.

On a national level, for 2020 the average installation costs of individual customer-sized solar PV facilities in the 5 - 20 kW range are currently estimated to be approximately $3,000 per installed kW prior to the application of the ITC. For a 100-kW system that might be utilized for larger single pumping loads, the per-unit costs are estimated to be approximately $2,100 per installed kW. However, research conducted by the APM Analysis Team indicated that average small-scale solar PV installation costs in Oregon and California tend to be somewhat higher than the national average.[28]

Customers primarily receive financial benefits associated with small-scale solar PV facilities through the use of PacifiCorp's net metering programs that are in effect in both Oregon and California that allow customers to either sell self-generation in excess of the customer's load to PacifiCorp (in California), or to "bank" excess generation in one period to be counted towards the customer's electrical usage in a future period (in Oregon).[29] However, as is discussed further in Chapter 8, it is extremely important that water users who may be interested in acquiring small-scale solar PV systems carefully review the fine details of the net metering policies in effect in Oregon and California in order to fully assess their own specific cost/benefit situation.

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[27] It is important to note that customer-owned self-generation cannot be used to avoid certain PacifiCorp billing charges such as the annual Basic Charge that PacifiCorp accesses under its irrigation/drainage rate schedules in both Oregon and California. It is, however, possible for self-generators to reduce some portion of their PacifiCorp Load Size charges which are accessed based upon the irrigation customer's highest power usage in two separate months.

[28] For example, the article titled How Much Do Solar Panels Cost With Installation in 2020, available at www.earthingtechling.com/solar-panel-cost, states that the forecasted average installation cost for small scale solar PV systems in Oregon is $3.72/Watt ($3,720/kW).

[29] Details of PacifiCorp's net metering programs that are currently in effect in Oregon and California are discussed in more detail in Chapter 8 (APM No. 2).

Small-Scale Solar PV System Installation Costs

Based upon indicative price quotes developed by the Team using several on-line pricing tools and other publicly available information, the installation cost of a generic fixed-rack, 40 kW solar PV system [30] located approximately one mile south of downtown Klamath Falls, OR would be approximately 3,520/kW, prior to the application of the currently available financial incentives.[31] Following the application of the ITC and Energy Trust of Oregon financial incentives, the installation cost for an Oregon facility drops to $2,546/kW while in the California portion of the Upper Klamath Basin the cost would be $2,605/kW.

It should be noted that there are several different configurations of small-scale Solar PV systems that are available to residential/farm customers; for example, a fixed-rack system versus a multi-axis system (where the panels track of movement of the sun across the sky) or panels that have different energy conversion efficiencies. Given these options and differences in local site conditions, there can be a relatively wide range - perhaps +/- 15% of per-Kw installation costs for small-scale solar PV systems located in the same general geographical region. Therefore, it is important that water users receive specific, customized price quotes for the exact solar PV system configuration(s) they may be considering.

Small-Scale Solar PV System Generation Production in the Upper Klamath Basin

Several publicly available analytical tools are available to assist potential purchasers of solar PV systems/facilities in estimating the amount of electricity that will be produced at their local location. One such tool that was utilized by the APM Analysis Team is the PVWatts on-line calculator developed by the National Renewable Energy Laboratory.[32] The PVWatts tool allows users to custom-build potential PV systems of varying sizes and configurations and then compute the average amount (in kwh) of annual, monthly, and even hourly power production that they can expect to receive using actual solar radiation data recorded at multiple sites throughout the United States.

Fortunately, one of the solar radiation reference sites incorporated into the PVWatts tool is located very near to of the city Klamath Falls; historical solar data from this site was therefore utilized by the APM Analysis Team in order to derive generation estimates for small-scale Solar PV facilities in both the Oregon and California portion of the Upper Klamath Basin. Using the standard loss parameters incorporated into PVWatts and assuming an installation of standard-efficiency panels on a fixed-rack mount, the annual average forecasted annual generation for the generic 40 kW solar PV

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[30] The raw electrical output produced by solar PV panels is so-called Direct Current or "DC". However, for this electrical output to be usable to off-set residential, commercial, or farm electrical loads (or to be supplied to the bulk power grid from a large facility) it must first be converted into Alternating Current or "AC" through the use of a device called an inverter. This conversation process entails some electrical losses, however, so that the net amount of AC power delivered to a residence or pumping load is less than the original amount of DC power being produced off the solar panels. For consistency, all solar PV facility sizes, annual generation amounts, costs, and benefit figures cited in this Report are referenced to AC power quantities.

[31] For comparison purposes, a 50 HP fixed-speed irrigation pump would consume approximately 37.3 KW of power.

[32] NREL's PVWatts calculator is available at https://pvwatts.nrel.gov/.

facility was determined to be 70,464 kWh/year. This amount of generation equates to an annual capacity factor of 20.1%.

Small-Scale Solar PV System Levelized Cost of Generation

In evaluating the APMs that involve the potential development of new electrical generating facilities (of any scale), the APM Analysis Team utilized a widely-used industry metric known as the Levelized Cost of Energy or "LCOE".[33] The LCOE of a new generating facility is a measure of the forecasted average (or levelized) cost of producing energy from the facility across its assumed lifetime. Some of the key inputs to an LCOE calculation include: 1) the initial upfront investment amount, also referred to as the "overnight capital cost", 2) ongoing O&M costs for producing power, 3) fuel costs (if applicable), 4) the annual amount of energy to be produced, and 5) a long-term discount rate (in percent) that is used to discount future cash flows. In particular, LCOE is a useful metric in comparing the relative expected long-term cost of producing electricity from multiple different available alternatives.

The APM Analysis Team performed an appraisal-level LCOE evaluation for small-scale solar using the per-unit installation costs noted above (after the application of available financial incentives) and using an assumed 25-year useful life of the solar PV panels and associated system equipment. The 25-year LCOE for the generic 40 kW solar PV system ranged from approximately 6.763 ¢/kWh to 8.819 ¢/kWh for an installation in the Oregon portion of the Upper Klamath Basin to 6.920 ¢/kWh to 9.024 ¢/kWh for an installation in California.

Small-Scale Solar PV System Cost/Benefit Results

In performing its evaluation of small-scale Solar PV facilities in the Upper Klamath Basin, the APM Analysis Team identified that for most potential installations, the overall cost/benefit results are especially sensitive to the following key issues: 1) the amount of available financial incentives, 2) the annual capacity factor for the selected system, 3) the assumed future value of avoided PacifiCorp electricity purchases, 4) net metering impacts associated with highly seasonal irrigation/drainage loads, and 5) accurately identifying the PacifiCorp charges that cannot be bypassed via self-generation. In particular, it is imperative that any analysis of small-scale solar PV accurately incorporate the net-metering rules in place in Oregon and California and specifically, the fine details of the Net Excess Generation ("NEG") accounting mechanisms that are incorporated into both programs.

Because the overall cost/benefit economics of utilizing small-scale solar PV systems to serve seasonal irrigation loads in the Upper Klamath Basin is so highly intertwined with the mechanics of the Oregon and California net-metering policies, the results of these analyses are discussed in the Net Metering Chapter (Chapter 8/APM No. 2).

The one exception to the above statement is the limited case where a water-user in the Basin may desire to power an isolated electrical load that is not (or will not be) interconnected to PacifiCorp's electrical system. In this case, the Oregon and California net metering policies would not apply, and the generation produced from the small Solar PV facility would be fed directly to the load. The

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[33] It is noted that the earlier CAPP Analysis also utilized the LCOE metric to compare the various generation alternatives that were evaluated at that time.

water-user could then compare the LCOE for a small-scale Solar PV system directly against other available alternatives.

Alternative 2 - Shared/Community Facilities

Overview/General Description

Mid-scale solar PV systems, in the range of roughly 1 MW up to approximately 5 MW, can be developed to serve a group of customers or even a small community. Often referred to as "Shared Solar", "Community Solar", or "Solar Gardens", these installations can provide several benefits over small-scale, individual customer-based solar PV facilities. For discussion purposes, these facilities are referred to hereafter as shared solar facilities. A primary feature of these intermediate-sized solar PV facilities is that multiple electric customers of the same electric utility can each receive a portion of the power produced from a single, centralized project, with the associated benefits being reflected on each customer's individual power bill.

Oregon has enacted a state-wide shared-solar program known as the Oregon Community Solar Program.[34] This new program would allow for the development of one or more shared-solar PV facilities to be developed in the Oregon portion of the Upper Klamath Basin pursuant to established sets of design and implementation criteria. The State of California, however, has not enacted similar wide-ranging policies and the development of shared-solar facilities in that state has been very limited. Currently, PacifiCorp does not offer a shared-solar program in their California service territory; therefore, this solar PV alternative is focused solely on irrigation/drainage customers located in the Oregon portion of the Basin.

Potential Benefits

The primary benefit of shared solar PV facilities is one of economies of scale, meaning the per-unit installation costs in moving from small-size to mid-sized solar PV facilities tends to decrease (quite rapidly) as the total installed generating capacity of the facility increases. These economies of scale, when combined with the sharing aspect of such centralized PV facilities, allows individual customers to essentially acquire a source of "self-generation" at an overall lower cost than they could likely achieve by developing their own customer-specific facilities.

Another key benefit of shared solar PV facilities is that there is no need for individual customers to site the panels on their own property (and potentially take some farmland out of production). In addition, the initial development of the facility and ongoing O&M functions (such as washing the panels and conducting regular equipment maintenance) are handled by centralized personnel rather than by individual customers.

Potential Challenges

There are several challenges to be dealt with as the size of solar PV facilities are increased from the individual customer level to the shared/community level including site availability, more complicated electrical interconnection requirements, additional local permitting and public review processes, potential visual impacts, and security.

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[34] A comprehensive description of the Oregon Community Solar Program is available at: https://www.oregoncsp.org/p/home

In particular, shared solar PV installations would require interconnection to the electric grid at higher voltages (likely at least at 13.2 kV) than individual behind-the-meter type installations. This would require each proposed community solar facility to submit a formal interconnection request to PacifiCorp. After receiving such a request, PacifiCorp would then perform a transmission/distribution system impacts study to determine: 1) if the proposed solar PV project could feasibly be interconnected to the grid at the specific location specified in the Request, 2) the estimated costs of the at-site interconnection facilities including any new transmission or distribution lines, and 3) if the proposed new project would require any upgrades or reinforcements downstream of the plant's interconnection point on PacifiCorp's transmission and distribution system in order to maintain overall system reliability.

The above referenced interconnection request and companion study involves a formal multi-step process that can easily stretch over a twelve-month period or longer. In addition, the costs associated with PacifiCorp performing the required studies need to be funded by the entity who submitted the interconnection request. Finally, PacifiCorp's interconnection request process operates on a non-discriminatory "first-come, first-served" basis; therefore, it processes the requests and performs the associated studies in the order that it received the interconnection requests. This "queuing" process can result in further delays to a proposed timeline for a new generating project depending upon the number of new interconnection requests that a transmission operator is processing at a given time.[35]

An important design constraint for proposed shared solar PV facilities to be developed in Oregon is the net metering size limit that has been implemented by the state. While the net-metering topic is discussed in more detail in Chapter 8, it suffices to say that this policy essentially acts to restrict the size of shared/community solar PV facilities to a maximum of 2,000 kW in Oregon, even though larger shared facilities might feasibly be developed in the Upper Klamath Basin that could generate power at a lower overall cost (i.e. again through economies of scale). Therefore, the size range of solar PV facilities being evaluated under this APM alternative has been dictated more by state regulatory policies rather than by technical considerations.

Siting Considerations

The two main siting constraints as solar PV generating facilities are scaled up from individual customer/load size to the shared/community size are: 1) the need for additional land/space, and 2) locations that minimize electrical interconnection costs with the existing distribution and transmission infrastructure. In particular, large tracts of open land that are otherwise suitable for the placement of solar PV panels (i.e. good southern exposure, no overhanging trees, etc.) may be located in remote areas and located long distances away from existing transmission or distribution lines.

Energy Storage Options

Energy storage using either lithium-ion or other types of batteries can be installed in tandem with shared solar PV facilities to perform short-term generation firming and extending the facility's daily generation profile across a longer time period. Like solar PV panels, battery storage technology is

[35] It is not uncommon for transmission operators in the Pacific Northwest (such as PacifiCorp) to have dozens to hundreds of new requests in their generation interconnection queues at any given time.

very scalable in that the individual battery cells are relatively compact and modular; to create larger energy storage capabilities, individual cells are simply interconnected through a shared invertor and other common control equipment.

Financial Incentives for Shared Solar PV Systems

The same up-front financial incentives that are available to small-scale solar PV systems in the Upper Klamath Basin (as discussed in the previous sub-chapter) are also available for shared solar facilities as well. However, in the case of shared solar facilities, the benefits of the financial incentives and the economics of scale benefits are effectively combined to drive the overall dollar per-kW installation cost (and the associated LCOE) of a facility in the 2,000 kW size range to a significantly lower level than that of small-scale solar PV systems. These economies, in turn, may also allow for the development of shared solar facilities that utilize more efficient solar panels or single-tracking or dual-tracking solar arrays.

Anticipated Net Power Cost Savings

The primary benefit of shared solar PV facilities is that they offer many of the same benefits as smaller sized individual installations, but at a lower dollar-per-kW installation cost and a lower LCOE.

Although shared solar PV facilities are not located behind a customer's meter like a small-scale/individual system, they are effectively treated as such from a PacifiCorp billing perspective. Individual customer who have signed up for a share of a community solar PV facility can therefore directly avoid their energy-related PacifiCorp billing charges on a kWh-for-kWh basis just as if they had their own on-site/behind the meter solar system. However, due to economies of scale, the cost of the generation being produced from the shared solar PV facility is likely to be lower than what the customer could produce from their own on-site solar system which, in turn, would increase the difference between the avoided PacifiCorp charges and the customer's cost of replacing that energy (which, in turn, acts to increase the customer's net power cost savings).[36]

Customers that participate in a shared Solar PV facility also utilize the Oregon net billing procedures in order to effectively match up their annual energy usage with the annual generation output of the shared facility in order to receive their allocated amount of PacifiCorp billing credits. However, similar to the case of small-scale Solar PV systems, certain provisions contained in the net billing procedures are not advantageous when applied to highly seasonal irrigation/drainage loads. This important topic will again be discussed in Chapter 8.

Shared Solar PV System Installation Costs

Based upon indicative price quotes developed by the Team using several publicly available on-line pricing tools and other information, the installation cost of a generic single-axis tracking, 2,000 kW shared solar PV facility located approximately one mile south of downtown Klamath Falls, is estimated to be approximately $2,110/kW, prior to the application of the currently available

[36] It should be noted that the cents per kwh PacifiCorp billing credit that customers of shared Solar PV facilities receive is calculated in a slightly different fashion than if they installed their own on-site system and that this credit could be lower than what they would have received from an individual customer-owned solar PV system.

financial incentives. Following the application of the ITC and Energy Trust of Oregon financial incentives, the installation cost figure drops to $1,502/kW.

The per-unit installation costs associated with shared solar PV facilities are also somewhat dependent upon local site conditions, however not to as high a degree as small-scale/individual systems. It is assumed that the developer of a proposed shared solar PV facility would consider multiple potential sites and choose the one that afforded the best cost/benefit balance.

Shared Solar PV System Generation Production in the Upper Klamath Basin

The APM Analysis Team again utilized the PVWatts on-line tool to derive the expected annual generation output of a generic shared solar PV facility to be located near the city of Klamath Falls. Using the standard loss parameters incorporated into PVWatts and assuming the installation of premium-efficiency panels on a single-axis rack mount, the annual average forecasted annual generation for the generic 2,000 kW facility was determined to be 4,200,262 kWh/year. This amount of generation equates to an annual capacity factor of 24.0%.

Shared Solar PV System Levelized Generation Cost

The APM Analysis Team conducted an appraisal-level LCOE analysis for the generic shared Solar PV facility using the per-unit installation costs noted above (after the application of available financial incentives) and using an assumed 25-year useful life of the solar PV panels and associated system equipment. In addition, ongoing annual O&M costs were estimated to be $13.60/kW-yr. The 25-year LCOE for the generic 2,000 kW solar PV facility ranged between approximately 4.102 ¢/kWh to 5.252 ¢/kWh.

Shared Solar PV System Cost/Benefit Results

In performing its evaluation of shared solar PV facilities in the Upper Klamath Basin, the APM Analysis Team identified that for most potential installations the overall cost/benefit results are especially sensitive to the following key issues: 1) the amount of available financial incentives, 2) the annual capacity factor for the selected system, 3) the assumed future value of avoided PacifiCorp electricity purchases, 4) net metering impacts associated with highly seasonal irrigation/drainage loads, and 5) accurately identifying the PacifiCorp charges that cannot be bypass via self-generation. It is imperative that any analysis of shared solar PV accurately incorporate the net-metering rules in place in Oregon regarding the Net Excess Generation accounting mechanism.

Because the overall cost/benefit economics of shared solar PV facilities in the Upper Klamath Basin is so highly intertwined with the mechanics of the Oregon net-metering policy, the results of these analyses are discussed in the Net Metering Chapter (Chapter 8, APM No. 2).

Alternative 3 – Large-Scale/Grid-Scale Facilities

Overview/General Description

For the purpose of this APM Report, large-scale (also referred to as grid-scale) solar PV installations are considered to be those facilities with total installed capacity greater than 2,000 kW in Oregon and 1,000 kW in California. However, from a practical standpoint, many regional utilities consider grid-scale solar PV facilities to be 25 MW or larger, with a current upper limit of around 200 MW.[37] Electricity generated at grid-scale solar PV facilities would not - with one possible exception - be associated with serving any particular customer (or group of customers') end-use loads in the Upper Klamath Basin; rather the power output from such facilities could be sold at wholesale to either PacifiCorp, or potentially to other Pacific Northwest electric utilities. Sales would be made under a long-term purchased power agreement, pursuant to either: 1) the Public Utility Regulatory Policy Act ("PURPA"), or 2) an individual agreement to be negotiated between the seller and purchaser(s).

The one possible exception referenced above is that it may be possible for Reclamation to develop one or more grid-scale solar PV generating plants in the Upper Klamath Basin to be part of a new Federal Project-use Power supply portfolio dedicated to providing low-cost power to Reclamation's Klamath Project pumping and drainage loads. In this case, the power output from the Project's large solar PV plant(s) would be wheeled across PacifiCorp's transmission and distribution systems to one or more specific Reclamation loads.[38] This concept is discussed further in Chapter 14 (APM No. 8).

Potential Benefits

Due to a combination of lower capital investment costs, improved panel efficiencies, and government tax incentives, large Solar PV plants can be competitive at grid-scale with other electric generating technologies such as wind and natural gas fired combustion turbines. However, as many states in the Pacific Northwest are enacting Green-house Gas reduction programs and increasing their renewable portfolio standards, wind and solar are emerging as the primary candidates for new resource development to comply with these mandates.

Development of grid-scale solar PV facilities in the Upper Klamath Basin would have several benefits. First, the Basin's location in south-central Oregon is conducive to solar PV developments due to favorable solar radiation levels and less cloudy conditions than potential sites located on the west side of the Cascade Mountain range. Second, there are multiple existing transmission lines that traverse through the Basin and in areas near the Basin. And finally, large-scale solar PV facilities could help replace a portion of - or perhaps all of - the approximately 180 MW of capacity and associated energy that PacifiCorp will lose when it retires and removes four hydroelectric dams located on the Klamath River.[39]

Potential Challenges

A 25 MW to 200 MW size solar PV facility would need to interconnect at a transmission-level voltage of 115 KV or higher. In particular, large tracts of open land that are otherwise suitable for the placement of solar PV panels (i.e. good southern exposure, no overhanging trees, etc.) may be located in remote areas and located long distances away from existing transmission or distribution lines. Facilities of this size would be subject to multiple permitting processes which can add both costs and risk to the project.

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[37] From a technical standpoint, grid-scale solar PV facilities could be larger than 200 MW, however the maximum size of a single facility is often limited by the space required for the placement of the solar panels.
[38] This is not a novel concept; some of the Reclamation pumping loads in the Minidoka Project are served by Federal Project-use Power (generated at multiple Federally-owned dams located in southern Idaho) that is wheeled across transmission/distribution facilities owned by Idaho Power.
[39] The four Klamath River hydroelectric facilities that PacifiCorp will be removing are: 1) COPCO 1 (28,000 kW), 2) COPCO 2 (34,000 kW), Iron Gate (18,800 kW) and J.C. Boyle (98,000 kW).

The primary challenge to a grid-scale solar PV facility to be located in the Upper Klamath Basin is the need for the project's developer(s) to secure a long-term (i.e. at least ten years in length and preferably 20 year) power sales agreement with one or more purchasers, likely to be regional electric utilities. In order to secure financing for a project of this magnitude, lenders will generally require that the developer demonstrate the project has a long-term, known revenue stream that will be used to pay off the capital investment in the project. Securing one or more long-term power sales agreements - with one or more regional utilities - for a project of this magnitude could be a potentially time-consuming (and complex) process.

Siting Considerations

The two main siting constraints as solar PV generating facilities are scaled up from the shared size to utility/grid size are again: 1) the need for additional land/space, and 2) locations that minimize both local electrical interconnection costs and the need for other potential transmission system upgrades. For example, a 100 MW solar PV facility in the Upper Klamath Basin would require approximately 1,000 – 1,200 acres of land. Also, as the installed capacity of proposed new generating facilities increase in size, the number of suitable sites from a transmission perspective tends to decrease which further constrains potential development locations. A generating facility of this size would also require an increased need for site security as such a facility would be considered to be part of the critical infrastructure of the regional bulk power system.

Energy Storage Options

The primary energy storage alternative for grid-scale solar PV facilities would likely, again, utilize battery technology, at least for on-site storage options. A present, there are only a few battery storage facilities in the western U.S. that are at grid-scale although the Los Angeles Department of Water and Power and 8minute Solar Energy recently announced plans to develop a 200 MW solar PV project to be coupled with a 200 MW battery storage facility. It is also possible for new grid-scale solar PV plants to be coupled with hydroelectric pumped storage projects as the energy storage medium although hydro pumped storage plants have much more specific siting requirements than batteries storage facilities.[40]

Coupling energy storage with solar PV facilities at grid-scale provides opportunities for utilities and grid operators to not only firm up the output of the solar PV generation but to also actively utilize the combined output of the solar/battery facility as a source of short-term dispatchable capacity. In addition, the ability to use the battery storage to extend or reshape the predictable and very steep generation ramps that occur at solar PV facilities as the sun rises and sets is a valuable attribute for the electric utilities as they attempt to integrate more intermittent renewable resources onto the grid while maintaining a high level of system reliability.

The value of adding battery storage to a grid scale solar PV facility is not a function of the net metering programs in place in Oregon or California (plants of this size do not qualify for these programs), but rather is derived through the market value of a class of power products in the regional wholesale power markets that are typically referred to as "ancillary services". Ancillary services are a set of discrete power products that provide short-term operating flexibility and

[40] One hydroelectric pumped storage facility (the Swan Lake project) that is proposed for future development in the Pacific Northwest region would be located near to the Upper Klamath Basin.

reliability to the bulk power grid. A generating facility that can provide such services can earn additional revenues in the wholesale power markets above and beyond the price it receives for energy production alone.

Anticipated Net Power Cost Savings

The potential benefits to be derived from utility-scale solar PV development in the Basin are a function of two primary drivers: 1) the cost of constructing and maintaining the facility, and 2) the value derived from the generation output and how that value is monetized and distributed to covered water users in the form of either direct, or indirect benefits. These different cost/benefit components are discussed separately below:

Available Financial Incentives for Large-Scale Solar PV Systems

The Federal Investment Tax Credit can be utilized to directly off-set a portion of the developer's overall installation cost of new large-scale Solar PV facility. For 2020, the ITC is set at 26% and drops to 22% in 2022. In 2023 it drops further to 10%. Like the case for small-scale and shared solar PV facilities, the ITC acts to significantly reduce the up-front investment cost of a grid-scale solar PV facility, thereby lowering its long-term LCOE.

Large Solar PV System Installation Costs

Based upon indicative price quotes developed by the Team using several publicly available on-line pricing tools and other information, the installation cost of a generic dual-axis tracking, 100 MW large solar PV facility located in the Upper Klamath Basin is estimated to be approximately $1,210/kW, prior to the application of the currently available financial incentives. Following the application of the ITC, the installation cost figure drops to $895/kW.

Large-Scale Solar PV System Generation Production in the Upper Klamath Basin

The APM Analysis Team utilized the PVWatts on-line tool to derive the expected annual generation output of a generic, 100 MW large-scale solar PV facility to be located near the city of Klamath Falls. Using the standard loss parameters incorporated into PVWatts and assuming the installation of premium-efficiency panels on a dual-axis rack mount, the annual average forecasted annual generation was determined to be 259,861 Mwh/year. This amount of generation equates to an annual capacity factor of 29.7%.

Large-Scale Solar PV System Levelized Generation Cost

The APM Analysis Team performed an appraisal-level LCOE analysis for the generic 100 MW grid-scale solar PV facility using the per-unit installation costs noted above (after the application of available financial incentives) and using an assumed 25-year useful life of the solar PV panels and associated facility equipment. In addition, ongoing annual O&M costs were estimated to be $27.19 $/kW-yr. The 25-year LCOE for the generic 100 MW solar PV facility ranged from approximately 2.832 ¢/kWh to 3.535 ¢/kWh.

Large-Scale Solar PV System Cost/Benefit Results

Since Solar PV facilities larger than 2,000 kW do not qualify to be net-metered in Oregon (or in the California portion of the Upper Klamath Basin) the value proposition is quite different as compared to the development of small-scale or shared solar PV facilities. Therefore, the generation output of grid-scale solar PV facilities cannot be used to directly off-set a portion of the charges that appear on an individual electric customer's power bills from PacifiCorp under the existing net metering programs. However, as is discussed in more detail below, opportunities may exist for Basin water users to work in a collaborative fashion with PacifiCorp and the Rate Commissions to develop and implement a mutually-agreeable, customized power billing/credit mechanism that would emulate certain portions of the standard net metering procedures.

The net economic benefits associated with the development of one or more large-scale solar PV facilities located in the Upper Klamath Basin could be distributed to cover water users via two general mechanisms: 1) Direct Financial Benefits or, 2) Indirect Financial Benefits.

Direct Financial Benefits

Direct benefits could be provided to covered users through a special arrangement with PacifiCorp whereby a portion of the power generated at one or more new large-scale solar PV facilities to be located in the Basin would be dedicated to serving a portion of each users' electrical load.[41] Benefits could be conveyed to covered users via a billing credit on their monthly power bills from PacifiCorp under a mutually-agreed to accounting process that could incorporate some of the features contained in Oregon and California's standard net-billing arrangements. Depending on the size of the solar PV facilities to be developed, a portion of the power output not expressly dedicated to serving covered users loads could be retained by PacifiCorp for its own benefit (thereby providing PacifiCorp's out-of-Basin customers with a new carbon-free source of generation).

This arrangement might also incorporate some form of "short distance" PacifiCorp transmission and distribution charges that recognize the fact that the new solar PV generating facilities will likely be located in relatively close proximity to covered users' end-use loads. In addition, locating new utility-scale solar PV generation in the Basin might also provide transmission-related locational benefits to PacifiCorp by helping to replace the hydroelectric generation that will be lost when PacifiCorp removes its four dams on the Klamath River.

Indirect Financial Benefits

Indirect benefits could be provided to covered users through a series of long-term payments to be made based on the revenue streams earned from one or more grid-scale solar PV facilities to be developed in the Basin. In this case, the power output from the new solar PV facilities would not be linked to serving any particular customers' electric loads in the Basin, but rather the facilities' generation would be sold to one or more utilities in the region with a portion of the net revenues earned to be distributed among covered users.[42] The sales price received would be a negotiated, market-based price with one or more purchasers with the price incorporating the full value of the environmental attributes associated with carbon-free renewable resources. It is important to recognize, however, that when evaluating the cost/benefit economics of large-scale solar PV facilities that might be developed in the Upper Klamath Basin using this benefits distribution mechanism, that the sales price of the power produced at the facility will not be tied to PacifiCorp's prevailing retail electricity tariff prices. Rather it will be established by market forces in the regional wholesale power markets.

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41 Such an arrangement would likely be subject to approval by either the Oregon or California rate commissions.

42 This alternative is very similar to APM No. 3 (Out of Basin Investment) with the primary difference being that the solar PV facilities to be developed would be located within the Basin.

Given the currently-in-place Federal tax incentives for large-scale solar PV facilities and the upcoming large need for new sources of carbon-free renewable generation in the Pacific Northwest region, the general development environment for large-scale solar PV plants is believed to be relatively favorable. As an illustrative example, if the owner/operator of a generic 100 MW solar PV plant located in the Upper Klamath Basin – assumed to be developed in conjunction with a long-term profit sharing arrangement with covered water users - earned the equivalent of 1 cent/kWh of net profit on the generation produced by the facility, the annual average net benefit conveyed to covered users would be approximately $2.6 M/year.

Chapter 8 APM No. 2 - Net Metering (to be used in conjunction with other Measures)

Overview/General Description

Net metering programs have been established and implemented by many utilities in the Pacific Northwest region as an accounting mechanism whereby end-use electric customers can combine self-generated power with power purchases from their local utility provider and, in doing so, may lower their overall power purchase costs. In particular, significant recent reductions in the installation costs of solar PV panels have led to the situation where many residential and commercial power users have installed panels on their homes or office buildings and have effectively become "self-generators" whereby they provide some, or perhaps most, of the electricity that they consume.

There are two key concepts that are typically incorporated into the net metering programs: 1) how a local utility treats customer-produced electricity that is located "behind-the-meter", and 2) potential load/generation aggregation among multiple end-use retail power customers. These concepts are discussed separately in the following two chapters.

Treatment of Behind-the-Meter Customer-owned Generation

All electric utility customers are familiar with the concept of the electric meter that is installed at their home, farm, commercial establishment, or factory. The utility industry has long relied upon a "pay for what you use" financial model in that one's monthly power bill is largely a function of the amount of electricity that you consumed during that month, which is usually measured in terms of kilowatt-hours. Use more power during a month and your total power costs goes up. Use less power and your costs goes down.

However, what happens when an end-use customer actually creates electricity via their own generating facility? Where does that power go? Is the customer essentially "selling" the power to themselves or are they selling it to the local utility? If so, at what price does the customer sell power to the utility? And, does the utility have to buy the electricity that a customer produces that is more than their own on-site load? These are just some of the questions that customers, utilities, stakeholders, and regulators take into consideration when defining net metering programs.

In general, net metering programs allow end-use customers that self-generate to use that electricity generation to directly offset their power purchases from the local utility. In essence, by interconnecting the generating source on the *customer's side* of the electric meter, less power flows through the meter and the customer's receipt of power from the utility decreases. If the customer's load is greater than his or her self-generation amount at any given point in time, the customer is still a net purchaser of power from the utility. However, if the customer's self-generation amount is greater than his or her electric load, power flows backward through the meter and the customer is actually delivering power to the utility.

In this last case, a key provision of the net metering program is when the meter runs backwards, at what price does the utility "purchase" that power at from the customer? This amount is often referred to as the "net metering credit". There are various ways to establish net metering credits; however, all of these methodologies generally entail some tradeoffs between the interests of the customer (who favors a higher price for the credits), the local utility (who favors a lower price) and stakeholders/regulators who are attempting to implement and balance multiple different public policies. Another important issue is the time period across which the net billing credits are computed since both the customer's load and the amount of their self-generation are likely not constant values but are likely quite variable.[43]

Aggregated Generation Among Multiple End-Use Electricity Users

Utility regulators in both Oregon and California have approved programs whereby multiple individual power customers can purchase a portion of the generation produced at a single, centralized solar PV generating facility. These types of facilities are commonly referred to as shared or community solar facilities. Net metering shared solar PV facilities provide a double benefit to participating power customers in that: 1) a portion of the plant's generation output is dedicated to replacing the customer's power purchases from its local electric utility, and 2) the installation costs of the shared facility can be significantly lower than what the customer could achieve on their own (by developing a single-customer sized solar PV facility). However, PacifiCorp currently does not offer a shared solar PV option to its customers located in California.

PacifiCorp Net Metering Programs

The Oregon and California rate commissions have established net billing programs in their respective states that apply to the utilities that serve end-use retails loads in that state. Since PacifiCorp serves retail customers in both states, all water users located in the Upper Klamath Basin potentially have the ability to leverage these programs in some fashion (when used in conjunction with other APMs) to help reduce their power costs. While the net metering programs in the two states are similar in concept (simplified accounting mechanisms to match a customer's overall energy consumption with the customer's overall self-generation amounts), several important differences exist between the two programs that could have a material impact on the power-cost savings available to agricultural power customers in the Basin.

Treatment of Excess Energy Delivered to PacifiCorp

There is a significant difference in how a customer's self-generation that exceeds its electrical usage, (sometimes called Excess Energy or Net Excess Generation "NEG"), is treated under the Oregon

[43] For example, a power customer with a solar PV installation could be delivering power to the local utility during the daylight hours but then be receiving power during the nighttime hours.

and California net billing programs. [44] In California, the amounts paid by the local utility to the Customer for NEG is based upon the wholesale market value of power at the time that the NEG is delivered to the utility, as measured across a 12-month or in some cases a monthly period.[45] In this fashion, NEG amounts for power customers/self-generators are essentially "cashed-out" at prevailing, wholesale power market prices, with the proceeds from these sales being credited to the customer's PacifiCorp billing account. It should be noted that wholesale power prices in the California market are variable in nature and, over a long period of time, would be expected to be lower than – and potentially significantly lower than - the PacifiCorp retail tariff prices that customers avoid paying via self-generation.

However, under the Oregon net billing procedures, NEG amounts are treated very differently than in California. In contrast, no payments for NEG are made by the local utility to the self-generating customer. Instead, NEG amounts are tracked across a default 12-month accounting period beginning on April 1 of each year. Monthly NEG amounts for the current month are computed by the local utility and then carried forward into the next month, to be used to off-set a portion of customer's net electric usage in that future month. Unused NEG balances continue to carry forward to off-set the customer's usage until the following March 31. If the customer has a NEG balance as of March 31, that balance is forfeited by the customer (with no associated payment) and the NEG balance is re-set to zero to begin the next 12-month accounting period.[46]

The potential impacts of this 12-month NEG accounting mechanism as it relates to highly seasonal irrigation/drainage loads and self-generation located in the Oregon portion of the Basin is discussed further below.

Maximum Size Threshold for Shared Solar PV Facilities

There is a difference in Oregon and California regarding the maximum size solar PV generating facility that qualifies as a shared/community generating facility and can therefore receive the favored treatment of aggregating generation across a pool of multiple participating power customers. In California, the maximum size limit is 1,000 kW while in Oregon the current limit is 2,000 kW. However, PacifiCorp currently does not offer a shared solar option to its customers located in California.

It should be noted that the same general net-metering procedures that apply to individual customer self-generation facilities also applies to shared solar facilities, including the 12-month NEG carryforward accounting process.

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[44] Excess Energy is generally defined as the amount by which the customer's self-generation exceeds their electric load. These amounts represent the volumes of energy "sold" by the customers to the utility via the billing credit mechanism in place in California or carried forward into a future billing periods via the NEG banking mechanism in place in Oregon.
[45] The California Independent System Operator's DLAP (Default Load Aggregation Point) price(s) are used to derive the annual Excess Energy payments to customers.
[46] NEGs forfeited by customers at the end of the 12-month accounting period are transferred to PacifiCorp's low-income assistance fund and are valued (for the purpose of the transfer) at PacifiCorp's avoided cost rate.

Potential Benefits

The primary benefit of PacifiCorp's net metering programs that are in effect in both Oregon and California is that the programs allow customers to reduce their overall power costs by self-generating a portion of, or even all, of their own power needs by displacing energy formally purchased from PacifiCorp. A key feature of the program in Oregon is that self-generation in excess of the customer's load (or NEG) time can be "banked" and used to offset the customer's purchases from PacifiCorp during a future month within the same 12-month accounting period. For customers located in California, self-generation that is more than the customer's overall power usage across the 12-month (or in some cases monthly) accounting period is sold back to PacifiCorp at prevailing wholesale market prices.

The primary benefit of PacifiCorp's net metering programs (in both states) is that a customer's self-generation can be utilized to directly offset the customer's energy purchases from PacifiCorp. These "avoided purchases" are valued at PacifiCorp's full retail tariff rates, which effectively means that the self-generating customer can bypass not only PacifiCorp's own power supply costs but PacifiCorp's transmission and distribution costs as well. In general, all the PacifiCorp tariff charges that are billed on a per kWh basis can be reduced or eliminated through net metered self-generation. In addition, some forms of demand charges can also be moderately reduced.

It is important to note that while net metered self-generation allows customers to potentially bypass a large portion of its power purchase costs from PacifiCorp, there are some charges that cannot be avoided. For example, irrigation/drainage customers in both Oregon and California pay an annual Basic Charge to PacifiCorp that is in the form of a fixed dollar amount. This charge is not impacted by a customer's net metered self-generation.

For PacifiCorp individual irrigation customers located in Oregon and taking service under Schedule 41 the self-generation credit is currently 8.756 ¢/kWh.[47] For PacifiCorp irrigation customers located in California and taking service under Schedule PA-20 the self-generation credit is currently 11.905 ¢/kWh for loads less than 20 kW and 12.579 ¢/kWh for loads greater than 20 kW.[48]

Potential Challenges

Increasingly, as more and more end-use customers begin to self-generate a portion of their own power needs, electric utilities have begun to modify their retail electricity rate tariffs to reduce the amount of revenue they receive from per-unit usage charges and at the same time increase the utilities' revenue from either fixed charges (such as a monthly "customer charge") or establishing so-called "demand" or "capacity" charges that are based on a customer's maximum electricity usage during the billing period.

[47] For large irrigation/drainage loads that do not qualify to receive benefits under the BPA Residential Exchange Program, the current credit is 9.447¢/kWh.
[48] The self-generation credits for Oregon and California irrigation/drainage customers are based upon PacifiCorp's Schedule 41 (Oregon) and Schedule PA-20 (California) Price Summaries dated January 1, 2020.

Therefore, when evaluating the potential benefits of utilizing net billing programs with PacifiCorp as an APM (likely in conjunction with APM No. 1), it is important to recognize that utility rate tariffs and associated regulatory policies are not constant through time but rather are subject to change for a multitude of reasons. While it should be noted that PacifiCorp cannot, on its own, make such retail tariff changes without the approval of the Oregon and California Rate Commissions. Power users in the Upper Klamath Basin should recognize that there is some level of regulatory risk involved when attempting to utilize PacifiCorp's net metering programs as part of a long-term power cost reduction plan since: 1) the terms and conditions of the programs are subject to change, and 2) PacifiCorp's retail irrigation rate tariffs are also subject to change.[49]

The size restriction for shared solar PV facilities that is currently incorporated into PacifiCorp's Oregon net billing program is likely a limiting factor to potential power cost saving that can be achieved for water users that located in that portion of the Upper Klamath Basin since the established 2,000 kW size limit likely does not reflect the optimal size of a shared solar PV facility from an economy of scale standpoint.

Net Billing Accounting Impacts for Irrigation/Drainage Customers

The default PacifiCorp net-billing procedures in place in Oregon incorporate one key aspect that is very disadvantageous to highly seasonal power loads such as irrigation/drainage. While a "work around" may be possible in some cases, it is important that irrigation customers who are considering either installing self-generation or participating in a shared solar facility be aware of this issue when they perform their own cost/benefit analyses.

For Oregon customers, the primary issue of concern is the default 12-month NEG accounting period which runs from April 1 through March 31 of the following year. This particular accounting period is very disadvantageous for irrigation loads since a large portion of the annual energy produced by a solar PV facility cannot be used to displace purchases from PacifiCorp and is instead forfeited (at zero value) by the customer each March 31. For example, using actual 2017-2018 pumping load data provided by the Langell Valley Irrigation District and assuming the development of one or more small-scale solar PV facilities designed to supply 100% of Langell Valley's total pumping energy load, the APM Analysis Team determined that approximately 30.7% of the overall annual solar PV generation could not be credited to Langell Valley's PacifiCorp power bills and instead would be forfeited on March 31 of each year. Even if the solar PV facilities were scaled down to supply just 50% of Langell Valley's total annual electrical pumping load, the amount of forfeited annual generation would still be 28.0% of the overall annual generation.

Fortunately, a potential work-around appears to exist to help mitigate the above noted situation at least for small-scale/individual self-generation facilities. While Oregon's net-meting program uses a default April – March NEG accounting period, the program does allow an individual customer and PacifiCorp to agree to use a different 12-month period. However, the onus is on the customer to make this request and be knowledgeable as to which specific alternate 12-month period would be

[49] It should be noted that *any end-use customer* that purchases power from an electric utility is always subject to *some level* of regulatory risk since utility rate tariffs are subject to revision across time.

the most favorable for their own specific situation.[50] As an example as to how much of a difference changing the 12-month accounting period can make, for the case studies noted above for Langell Valley ID if the 12-month NEG accounting period were changed to end in October of each year, the forfeited NEG amounts would drop to between 0.0% and 2.6% of the overall annual solar PV generation.

The APM Analysis Team notes that it is unclear at the present time if an irrigation customer who is a participant in a shared solar PV facility in Oregon would have the option of using a NEG accounting period other than the default April – March period.[51]

For PacifiCorp irrigation net billing customers located in California, the primary issues of concern are: 1) the NEG accounting period that is utilized (i.e. monthly or 12-month), and 2) the wholesale value of power that is used to settle a customer's remaining NEG balances. This is especially a topic of interest for self-generating customers that may desire to utilize a monthly NEG accounting period since a relatively large portion of the annual generation from a small-scale solar PV facility would occur during months with zero irrigation loads, and would thereby be cashed out at prevailing wholesale power prices.

Anticipated Net Power Cost Savings

The net-metering programs in place in Oregon and California are designed to work in tandem with customer-owned self-generation facilities in order to assist customers in bypassing many of charges assessed by local utility providers under their standard retail sales tariffs. While net-metering can be applied to any form of self-generation, given the self-generation alternatives available to agricultural water/power users in the Upper Klamath Basin, it has been assumed for the purpose of this Report that this APM would be paired up with either small-scale/individual sized or shared/community sized solar PV facilities that were previously discussed under APM No.1.

The power cost savings that can be achieved by linking up APM No. 1 and APM No. 2 are a function of three primary factors: 1) the customer's cost of generation, 2) the customer's avoided energy purchase costs from PacifiCorp, and 3) the overall percentage of the annual self-generation produced that can be directly credited to offsetting the customer's energy purchases from PacifiCorp. The greater the difference between the customer's cost of generation and its avoided PacifiCorp energy purchase costs, the greater the net benefit received by the customer. Likewise, a customer's annual net benefit is maximized when 100% of the customer's annual self-generation can be directly credited against the customer's energy purchases from PacifiCorp.

Based upon the current differential between the cost of self-generating at small-scale and shared solar PV facilities in the Upper Klamath Basin and the PacifiCorp retail irrigation tariff charges that

[50] Based upon the APM Analysis Team's preliminary studies, the most favorable 12-month NEG accounting period for highly seasonal irrigation/drainage loads would be a period that ends in the last pumping month during the fall season.

[51] The Oregon Community Solar Program's 2020 Program Implementation Manual references the default April to March NEG accounting period, but it does not expressly state that one or more individual participants in the same shared solar PV facility could choose to utilize an alternate 2-month period. Implementation Manual at page 78.

can be bypassed, there appears to be reasonable opportunities for at least some Basin water/power users to enjoy a long-term, net positive economic benefit by developing in-Basin solar PV facilities. However, when performing its appraisal level cost-benefit analysis for this APM, the APM Analysis Team noted that the overall cost/benefit results of small-scale and shared solar PV facilities paired with the established net metering programs are very sensitive to several key input assumptions. In particular, the assumed future value of a customer's avoided energy purchase costs from PacifiCorp has a large impact as to whether a specific solar PV facility will produce a net positive benefit for its owner(s) across the assumed 25-year life of the equipment. In addition, for customers located in Oregon, the percentage of the annual self-generation produced that can be directly credited against the customer's energy purchases from PacifiCorp (via the 12-month NEG accounting mechanism) is also an important driver to the overall results of the cost/benefit analysis.

While the preliminary cost/benefit results of the APM are encouraging, ultimately it is the individual water-users in the Basin that will need to make their own assessments regarding several of the key assumptions that are incorporated into an individualized cost-benefit analysis that accurately reflects their own specific circumstances, in addition to determining their own payback thresholds relative to other potentially available alternative investments. To aid Basin water users in making these types of assessments, and is discussed further in Chapter 21 (Recommendations/Next Steps), the APM Analysis Team recommends that one or more analytical tools be developed that are specifically designed to: 1) assist water users with highly seasonal irrigation/drainage loads in evaluating the costs and benefits of developing small-scale and shared solar PV facilities given their own unique circumstances, and 2) allow water users to clearly be aware of, and vary if desired, the key assumptions that are incorporated into the analyses.

Chapter 9 APM No. 3 - Out-of-Basin Renewable Energy Investment

Overview/General Description

Most of the Affordable Power Measures discussed in this report are designed to directly reduce Upper Klamath Basin water users' power costs. However, this APM would reduce power costs in the Upper Klamath Basin in an indirect fashion by creating one or more investment vehicles that would be utilized to produce revenue streams that would, in turn, be passed along to covered power users in the Upper Klamath Basin.

While the AWIA does not specify any particular type of generating resource that might be developed either inside of, or outside of the Upper Klamath Basin in order to reduce power costs in the Basin, the legislation does state a preference for renewable resources.[52] Investment in renewable energy outside of the Upper Klamath Basin can be done in several ways, including a partnership with a developer of renewable generating resources or investments in renewable energy mutual funds, exchange traded funds, or yieldcos. The goal of such commercial arrangements would be to provide a long-term, known revenue stream to the sponsoring (likely non-profit) entity who, in turn, would pass through the associated dollar benefits to individual covered users to help offset these customers' power purchase costs from PacifiCorp.

Potential Benefits

The states of Washington, Oregon and California have all enacted various legislation and policies that will require the development of a considerable amount of new renewable energy resources across the next several decades. For example, in May 2019, Washington enacted legislation that will require electric utilities that serve end-use retail loads in that state to: 1) cease acquiring power supplies from coal-fired power plants by the end of 2025, and 2) have power generation portfolios that are 80% carbon free by 2030. Oregon also has in place renewable portfolio standards that will require electric utilities – including PacifiCorp – to meet 50% of their end-use retail loads with renewable resources by 2030. In addition, PacifiCorp recently announced that it will be retiring several more of its coal-fired power plants and that it intends to replace this lost generation with approximately 800 MW of new renewable resources.

There are several potential benefits of investments in renewable energy that are not necessarily tied to projects that would be in the Upper Klamath Basin. These include:

[52] The AWIA does not expressly define what is considered to be a renewable energy generating resource. However, resource types that are commonly considered to be renewable in the Pacific Northwest region include, but are not necessarily limited to, hydroelectric, wind, solar, tidal, biomass and geothermal.

- The ability for water users located in the Upper Klamath Basin to sponsor and invest in one or more entities that develop new renewable generating resources significantly expands the universe of potential renewable energy opportunities by considering locations outside of the Basin.

- An investment in an out-of-Basin renewable energy resource would not require the direct delivery of the facility's generation output to covered water users (which could potentially be expensive or not feasible under current regulatory restrictions). Instead, the power output of the facility would be sold to one or more third parties (likely regional electric utilities) with the financial proceeds from the sale(s) being distributed among covered water users in the Basin.

- The revenue stream(s) from the out-of-Basin renewable investments can be distributed among covered water-users through various means. Most notably, both On-Project and Off-Project covered water users could receive financial benefits under these arrangements.

- There could be an opportunity for interests in the Basin to work collaboratively with PacifiCorp to develop new renewable resources that would help PacifiCorp meet its newly expanded renewable resource acquisition goals while also providing associated financial benefits to covered water users in the Basin.

Potential Challenges

The three main constraints associated with renewable energy investments outside the Upper Klamath Basin are: 1) risk, 2) the need for investment capital, 3) the equitable distribution of benefits to covered water users, and 4) public perception. Any investment would require close evaluation of the finances, the partnership, and its future durability. Also, public perception of investment outside the Basin may be viewed unfavorably and could experience opposition from the Klamath Basin community for not reinvesting in Basin jobs.[53]

In addition to the above referenced constraints, the development of any new power generating facilities is subject to multiple regulatory permitting processes, the outcome of which is always subject to some level of uncertainty and potential unexpected costs. Also, the electric utility transmission interconnection process for new generating facilities (of any type) can be incredibly involved and time consuming as well.

Anticipated Net Power Cost Savings

Investment in out-of-Basin renewable energy opportunities would not directly reduce a covered-user's monthly power bill, but instead would provide a source of revenue to the user that would

[53] To the extent that the Enhancement Act places a priority on projects which promote regional Klamath Basin economic development, an out-of-basin investment might be considered to be incompatible as an APM. However, by creating more optimal and readily implementable power cost reduction opportunities, such investments serve to keep more Klamath Basin dollars at home, thereby promoting local economic development.

offset a portion of the user's power costs. The effective amount of reductions in customers' power costs is therefore difficult to assess at present since the savings would be primarily tied to: 1) the total net revenues earned from the out-of-Basin investment, and 2) the individual customer's allocated portion of the benefits.

The expected returns on an out-of-Basin investment in renewable energy are subject to a number of uncertainties including, but not necessarily limited to: 1) the specific structure of the investment vehicle, 2) long-term capital financing rates, 3) future Federal, State and Local tax policies, 4) future Federal, State and Local environmental policies including programs to reduce Green House Gas emissions, 5) Pacific Northwest regional electric utility load growth rates, and 6) future state-level renewable portfolio standards.[54]

Of particular note is that the renewable energy industry in the Pacific Northwest is extremely competitive with many established companies already having developed multiple projects throughout the region. Overall, the financial margins to be earned off the development of new out-of-Basin renewable energy resources will be determined largely by market forces. However, the current regulatory and environmental climates in Washington and Oregon is to not only encourage the development of new renewable resources – primarily wind and solar – but to also discourage (or outright prohibit) the development of new thermal-based generating plants including natural gas-fired plants.

An indication of the potential revenues that might be earned and distributed to covered users via an investment in an out-of-Basin renewable energy project were previously discussed in Chapter 7 in the context of the potential development of a generic large-scale, 100 MW solar PV facility to be located in the area of Klamath Falls, Oregon. This illustrative example indicated that a 100 MW solar PV facility with an annual generating capacity factor of 29.7% and earning a net profit of 1 cent/kWh on the generation produced (via a presumed long-term power sales agreement) would result in an overall annual profit amount of approximately $2.6 M. By comparison, a generic 100 MW solar PV plant located near Goldendale, Washington earning the same 1 cent/kWh profit margin would have an overall annual profit amount of approximately $2.4 M while the same generic plant located near La Pine, Oregon would have an annual profit of approximately $2.5 M.

[54] The 2016 CAPP Report projected that an out-of-basin renewable energy investment would provide an annual return of four percent on the capital investment.

Chapter 10 APM No. 4 - Time-of-Use Power Rates

Overview/General Information

Currently in the Pacific Northwest region, the majority of retail electricity customers – including most of the irrigation loads located in the Upper Klamath Basin – receive service under utility rate tariffs whereby the customer pays a constant rate for the electricity they consume no matter when they use the power during a monthly billing cycle. However, some utilities (including PacifiCorp on a limited pilot program basis) offer alternative rate tariffs whereby customers have the opportunity to reduce their overall power purchase costs by proactively modifying their electricity usage patterns.

Time-of-Use power rates are one such class of electric utility rate tariffs whereby end-use retail customers can self-manage a portion of their overall power costs by shifting their electricity usage patterns off of the utility's highest peak load periods (when the value of wholesale power is generally highest) and into periods when the utility's loads are lower such as during the night (when the value of wholesale power is generally lowest). The concept behind Time-of-Use rates is that by providing retail customers with "price signals" regarding the real-time value of electricity in the regional wholesale markets, customers can voluntarily choose to adjust their electricity usage patterns to the benefit of both the utility and the customer.[55]

PacifiCorp has implemented Pilot Time-of-Use Service programs that are available to a limited group of its irrigation customers located both in Oregon and California.[56] In Oregon the Time-of-Use rate tariff is referred to as Schedule 215 and in California the Time-of-Use tariff is Schedule PA-115. Currently, participation in both pilot programs has been limited by PacifiCorp to a small number of irrigation customers (100 in Oregon and 25 in California), however PacifiCorp has expressed a willingness to make both the Oregon and California time-of-use programs more widely available in the future.[57]

PacifiCorp's Oregon and California Pilot Time-of-Service rate tariffs are very similar, with the primary difference being the specific rate surcharges and discounts relative to the base energy rates

[55] High wholesale power prices tend to occur during power system "stress events" such as a summer heat wave or a major transmission outage, both of which could lead to shortage conditions and potential load curtailments.
[56] "Pilot" rate programs are typically newly developed rate tariffs where a utility desires to gather additional information before implementing the tariff on a long-term basis. Many pilot programs are also developed in conjunction with customer groups and other stakeholders. It is also common for the utility to limit participation in pilot rate programs to gain actual experience with a small group of customers before making the program more widely available.
[57] Any expansions of the PacifiCorp Pilot Time-of-Use programs that are currently in effect will be subject to the approval of the Oregon and California rate commissions.

specified in PacifiCorp's standard irrigation tariffs (which are Schedule 41 in Oregon and Schedule PA-20 in California). Key characteristics of the Pilot Time-of-Service programs are as follows:

- Both the Oregon and California programs are in effect during the "Prime Summer Season", which is defined as the period running from June 1 through August 31. During the Prime Summer Season, energy charge adjustments are applied to the base energy charges specified in Schedule 41 (Oregon) and PA-20 (California). No energy charge adjustments are applied outside of the Prime Season.
- On-Peak Periods are defined under both programs to be Monday through Friday 2:00 PM to 6:00 PM. Off-Peak Periods are all other days and hours including Independence Day.
- During the Prime Summer Season, the following price adjustments are applied to the Schedule 41 (Oregon) and Schedule PA-20 (California) base energy charges:

<u>Oregon</u>

On-Peak Period Energy Charge Adjustment = +22.313 cents/kWh

Off-Peak Period Energy Charge Adjustment = (3.161) cents/kWh

<u>California</u>

On-Peak Period Energy Charge Adjustment = +30.022 cents/kWh

Off-Peak Period Energy Charge Adjustment = (4.254) cents/kWh

- There are no price adjustments applied to the base Schedule 41 or Schedule PA-20 energy rates outside of the Prime Summer Season.
- During the first Prime Summer Season that a customer participates in either Pilot, if the customer's overall total cost across that Prime Summer Season exceeds 10% of what the customer's total power costs would have been under the base Schedule 41 or Schedule PA-20 rates, PacifiCorp will credit the difference back to the customer.
- Participation in either Pilot is voluntary. However, once a customer commits to participate in the Pilot, they are required to participate through the end of the next Prime Summer Season.

Potential Benefits

PacifiCorp's Pilot Time-of-Use rate tariffs provide individual irrigation customers located in both Oregon and California the opportunity to reduce their power costs during the three-month Prime Summer Season by shifting some, or perhaps all, of their electricity consumption off the designated On-Peak Hours. One key benefit of these Pilot programs is that PacifiCorp has pre-determined the exact days and hours that are designated as On-Peak Hours; this feature allows customers to plan their individual pumping schedules and associated power usage well in advance.

In addition, the exact price impacts of a customer shifting their power usage from the On-Peak Hours are known in advance as well since the Pilot Programs' price adjustments are pre-determined, fixed values. This feature allows customers to perform their own cost/benefit analyses and make proactive decisions regarding their electricity usage based upon real-time weather and crop conditions.

Potential Challenges

While PacifiCorp's Pilot Time-of-Use tariffs provide an opportunity for irrigation customers to reduce their power costs, <u>such reductions are not guaranteed</u>. In fact, a customer's monthly power bills during the three-month Prime Summer Season can actually be higher than what they would have been had the customer taken service under PacifiCorp's standard Schedule 41 (in Oregon) and Schedule PA-20 (in California) rate tariffs. For customers to be able to reduce their power costs under the Pilot programs, they must be able to modify their irrigation/water use practices in order to successfully shift a portion of their electricity usage from the designated On-Peak Hours to Off-Peak Hours.

For customers who successfully shift a portion of their electricity usage off the On-Peak Hours for the majority of the days in a month, those savings can quickly be "undone" if they fail to shift consumption on only a couple of other days within that same month. In other words, there is a relatively large dollar penalty for power usage during the designated "On-Peak" Hours on any given On-Peak Day (i.e. Monday – Friday). In addition, under the Pilot programs, customers are required to remain participants in the program through the end of their first Prime Summer Season (although PacifiCorp does cap the amount of the customer's power cost increase at 10%).

It is important to recognize that water users or districts located in the lower parts of the Klamath Project could be negatively impacted by the shifting of pumping operations occurring in the upper parts of the Project. Large-scale Time-of-Use programs have the potential to disrupt water deliveries in the Klamath Irrigation District and the Tulelake Irrigation District to an unknown degree, and to result in increased operational spills that increase the need for pumping (primarily at D Plant) and attendant power costs.

Anticipated Net Power Cost Savings

The power cost savings that can be achieved under PacifiCorp's Oregon and California Pilot Time-of-Use irrigation tariffs are solely a function of how much electricity consumption individual participating customers can successfully shift off the designated On-Peak Hours during the Prime Summer Season. However, customers' power costs could increase (relative to the base Schedule 41 and Schedule PA-20 costs) if the customer fails to shift enough of their consumption off of the On-Peak Hours.

Table 10-1 summarizes the overall monthly power cost reductions and increases for an Oregon irrigation customer who shifts differing amounts of their electricity consumption off the On-Peak Hours during the three-month Prime Summer Season:

Table 10-1. Monthly Power Costs Reductions/Increases During the Prime Summer Season Oregon Pilot Time-of-Use Irrigation Customers

Amount of Customer's On-Peak Hour Energy Usage Shift (Percent)	Increase/(Reduction) in Customer's PacifiCorp Energy Charges (Percent)
0	+15.3
20	+5.0
40	(5.3)
60	(15.5)
80	(25.8)
100	(36.1)

Note: The figures shown in Table 11-1 represent the percentage increase or reduction in the total monthly energy charges accessed by PacifiCorp to a participating Oregon irrigation customer.

Table 10-2 summarizes the overall monthly power cost reductions and increases for a California irrigation customer who shifts differing amounts of their electricity consumption off the On-Peak Hours during the three-month Prime Summer Season:

Table 10-2. Monthly Power Costs Reductions/Increases During the Prime Summer Season California Pilot Time-of-Use Irrigation Customers

Amount of Customer's On-Peak Hour Energy Usage Shift (Percent)	Increase/(Reduction) in Customer's PacifiCorp Energy Charges (Percent)
0	+14.2
20	+4.7
40	(4.9)
60	(14.5)
80	(24.0)
100	(33.6)

Note: The figures shown in Table 11-2 represent the percentage increase or reduction in the total monthly energy charges accessed by PacifiCorp to a participating California irrigation customer.

Chapter 11 APM No. 5 – Irrigation Load Control Programs

Overview/General Information

The majority of the power that is provided to customers by electric utilities in the Pacific Northwest region is delivered on a "firm" basis; that is the customer determines when and how much electricity they want to consume, and the utility strives to deliver that amount. However, under some system conditions, for example when overall customer demand for power is at its peak level, it may be more cost-efficient for the utility to reduce its deliveries of electricity to end-use customers rather than attempt to acquire additional power supplies (either by purchasing power in the short-term wholesale markets or potentially constructing new generating plants in the long-term).

One form of rate tariff that allows utilities to reduce their electric loads during time of system stress are referred to as "Demand Response" or "Load Control" programs.[58] As the names suggest, Load Control programs allow utilities to keep their total load and total resources in balance by adjusting the load side – as opposed to the generation side - of the equation. Since Load Control programs are primarily designed to help utilities meet their peak load demand, implementing such programs on a large-scale may negate the need for utilities to construct expensive new generating plants that may only need to be operated for a limited number of hours each year.

PacifiCorp has implemented an Irrigation Pilot Load Control Program that is available to its irrigation customers located in Oregon under Rate Schedule 105. In July 2019, PacifiCorp announced that it was extending and expanding this Pilot Program to, among other things, offer the Program to a broader set of customers including customers located outside of the Upper Klamath Basin. PacifiCorp also announced that it was modifying the Pilot to incorporate higher potential incentive payments to customers and its intent to automate portions of the Program for larger loads.[59]

PacifiCorp's Load Control Pilot Program differs from its Pilot Time-of-Use Programs in that the days and times that customers may be asked to reduce their electricity consumption are not pre-determined, but rather PacifiCorp will make load reduction requests to its participating customers on either a day-ahead or hour-ahead basis. So, while the overall goal of both Pilot Programs is similar - to reduce electricity demand during periods of electric system stress – the two Pilots attempt to achieve this through different means. In particular, the Load Control Pilot attempts to leverage

[58] Another rate program that allows utilities to curtail electricity deliveries to certain classes of customers are referred to as "Interruptible Tariffs".
[59] *See* Advice No. 19-008, Irrigation Load Control Program Pilot Expansion, PacifiCorp filing with the Oregon Public Utility Commission dated July 22, 2019.

situations where irrigation water users have real-time flexibility to modify their pumping operations, with the power-related benefits of this flexibility being shared between the customer and PacifiCorp.

Key characteristics of the PacifiCorp's Oregon Pilot Load Control Program are as follows:

- The period that the Pilot Program is in effect runs from the week including June 1 through the week including August 15. There is also a "Voluntary Period" that runs from August 15 to September 30.
- The Program hours are defined as all Weekdays, 12:00 PM to 8:00 PM Pacific Time.
- Incentive payments for load curtailments made by PacifiCorp on a day-ahead basis are $18/kW per year.[60] Incentive payments for load curtailments made by PacifiCorp on an hour-ahead basis are $30/kW per year.
- PacifiCorp can request load curtailments on a maximum of 52 hours per year. PacifiCorp is also limited to requesting a maximum of 20 curtailment events per year, with each event being no longer than 4 hours in duration.
- Participants in the Pilot may opt-out of curtailment requests issued by PacifiCorp; however, opting out will lower the participants' incentive payments on a proportional basis.

Potential Benefits

Individual irrigation customers' overall net power costs can be moderately reduced under the Pilot Program by allowing PacifiCorp to curtail their electricity usage on short notice in exchange for receiving incentive payments from PacifiCorp. Key benefits of this Pilot Program are:

- There is no penalty to the customer if the customer is unable to comply with a curtailment request from PacifiCorp. The customer receives incentive payments from PacifiCorp based upon the actual amount of power usage curtailment that it is able to provide.
- The greater the customer's ability to accept power curtailment notices from PacifiCorp, the higher the dollar payments that it receives.
- Customers that can curtail electricity usage on an hour-ahead (as opposed to a day-ahead basis) receive additional incentive payments from PacifiCorp.
- A customer's participation in the Pilot Program is voluntary.
- Customers can opt out of the Pilot Program (subject to notice requirements).

[60] For customers that participated in the Pilot Program in 2018 and for new participants in 2019 that participated prior to the Oregon Commission approving PacifiCorp's July 22, 2019 Pilot Expansion Proposal, the day-ahead incentive payment was $23/kW per year.

Potential Challenges

For irrigation customers to reduce their power costs under PacifiCorp's Pilot Load Control Program, customers must have a moderate to significant amount of short-term flexibility regarding their pumping operations. For some customers, this may entail having some level of water storage available, or alternatively, the ability to "make up" pumping (or sprinkler) operations in the hours following a load curtailment event.

A key provision of the Pilot Program is that the exact days and hours that PacifiCorp can call for a load reduction is not pre-determined; rather PacifiCorp will make this determination based upon a variety of factors that are outside of the customer's control. To benefit from the Pilot, and especially to receive the higher hour-ahead curtailment incentive payments, customers may incur costs associated with having personnel available on short notice to shut down/restart water delivery equipment. It is also possible that customers could endure crop-related losses if curtailments occur during particularly sensitive time periods (although customers do have the ability to opt-out of the curtailment events).

Similar to the case under PacifiCorp's Pilot Time-of-Use program (APM No. 4), water users located in the lower parts of the Klamath Project could be negatively impacted by the shifting of pumping operations occurring in the upper parts of the Project. Large-scale load curtailments have the potential to disrupt water deliveries in the Klamath Irrigation District and the Tulelake Irrigation District to an unknown degree.

Anticipated Net Power Cost Savings

Power cost savings available to customers who choose to take service under PacifiCorp's Irrigation Pilot Load Control Program, as compared to taking service under the standard Schedule 41 rates, are primarily a function of four key factors: 1) the size of the associated pumping equipment, 2) how often PacifiCorp issues load curtailment requests, 3) how often the customer opts out of load curtailment requests, and 4) whether or not the customer can respond to load curtailment requests on an hour-ahead as opposed to a day-ahead basis.

Table 11-1 illustrates the maximum power cost savings that an irrigation customer could receive – in the form of a one-time annual incentive payment received from PacifiCorp - under the Pilot Program given several different assumptions.

Table 11-1. Irrigation Customer Annual Power Cost Savings under the Pilot Program

Example Load	Day-Ahead Curtailment Max Annual Incentive Payment ($)	Day-Ahead Annual Incentive Payment as a Percent of Annual Power Costs (%)	Hour-Ahead Curtailment Max Annual Incentive Payment ($)	Hour-Ahead Annual Incentive Payment as a Percent of Annual Power Costs (%)
10 HP Pump	135	10.6	225	17.6
50 HP Pump	675	10.6	1,125	17.6
100 HP Pump	1,350	10.6	2,250	17.7

Note: The total annual power costs for the three example loads were derived using PacifiCorp's currently-in-effect Schedule 41 irrigation tariff rates assuming that the pumps are operated only during the months of May – September at an average monthly load factor of 50%. At an average monthly load factor of 100%, the resultant annual cost savings for all three example loads would be 5.5% for Day-Ahead curtailments and 9.1% for Hour-Ahead curtailments.

Combining Irrigation Load Control with Self-Generation

Some water users in the Oregon portion of the Upper Klamath Basin may be interested in participating in PacifiCorp's Irrigation Load Control Program (i.e. this APM Mo. 5) while also installing some form of self-generation such as small-scale solar PV (APM No. 1). In such cases, a customer's net dollar benefit associated with each separate APM is directly additive in nature (on a one-for-one basis) given the net metering and NEG accounting mechanisms that are currently in place in Oregon. The one potential negative aspect of this arrangement, however, is that for self-generation systems that are designed to off-set a very high percentage of the irrigation customer's overall annual load (i.e. roughly 95-100%), participating in the load control program to a high degree could result in the customer forfeiting additional NEG credits at the end of the net-billing 12-month accounting period. However, the customer has some level of control over these situations by: 1) installing a lower level of self-generation capacity relative to the customer's expected annual average irrigation/drainage load, or 2) voluntarily opting out of PacifiCorp load reduction events.

Chapter 12 APM No. 6 - Small Hydroelectric Generation Plant Development

Overview/General Information

The incorporation of hydroelectric generation into Reclamation irrigation projects located in the Pacific Northwest region is not a new or novel idea. In fact, in the Power Cost Benchmark analysis that accompanies this APM Report, all five of the Reclamation projects that were identified as being "Similar Projects" to the Klamath Project currently receive, and have for many years received, power produced at Federally-owned hydro plants that were developed as part of these projects' irrigation water delivery infrastructure.[61] However, largely due to the long-term power purchase agreements that were in place between Reclamation/Basin covered users and PacifiCorp between 1917 and 2006, Reclamation never developed any hydro generating facilities on the Klamath Project.

Smaller/low-head hydro generating plants can often be installed on existing water features including small dams, canals, irrigation drops, and even run-of-river from small diversions. Several potential sites for low-head hydro plants have been identified in the Oregon portion of the Upper Klamath Basin including PacifiCorp's Keno Dam, the Eastside and Westside Powerhouses, and several irrigation canals and conduits.

The CAPP Report identified and evaluated the potential installation of small hydro generation at six sites located on the Klamath Project, ranging in size from 300 kW to 3.8 MW. Of the six sites, the CAPP concluded that the installation of a 3.8 MW hydropower facility at Keno Dam appeared to be the most economically feasible alternative, in part due to the year-round flows available at this particular site. The CAPP Report did not identify any low-head hydro plant development sites in the California area of the Klamath Basin.[62]

In reviewing potential small hydro plant development in the Upper Klamath Basin, the APM Analysis Team noted that several companies are currently in various stages of developing new technologies for small hydro facilities (i.e. roughly in the 100 kW to 5,000 kW range) that may result in lower overall construction and life-cycle costs than traditional technologies that typically involve significant civil construction works. Some of these technologies are designed specifically to be installed at diversion structures in existing water canals with minimal footprints. For example, facilities utilizing a siphon design can be installed at existing check structures essentially in-line with

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[61] In addition, irrigation districts in some of the five Similar Projects have also constructed hydro generating plants that utilize the irrigation water delivery infrastructure that was originally developed by Reclamation.
[62] It should be noted that hydro generating facilities that incorporate newer "in-line" technical designs may be capable of feasibly producing power at low-head sites where conventionally designed hydro plants cannot. Therefore, it is possible that some small scale (sub-MW), on-farm hydro power generation capability may exist for sites located in the California portion of the Basin where adequate flow and head conditions prevail, preferably year- around to reduce the payback period.

the existing canal. An example of an early prototype facility that is currently in operation is Emrgy's hydrokinetic turbine plant, a series of ten each 10 kW machines located on a water supply canal operated by Denver Water near Golden, Colorado. The system generates enough electricity to supply approximately 7 homes a year.

Potential Benefits

The ability to generate power regardless of the time of day makes hydropower especially beneficial to power users and electric utilities. Notably, the seven months of the year when water is typically available in most Klamath Project irrigation canals and conduits encompasses the summer irrigation season which coincides with higher overall power demand in the Basin due to agricultural pumping operations. In the Lower Klamath region, winter season gravity diversion occurs; winter and early spring drainage pumping can be significant in that and other areas.

As part of the APM Analysis, the Team reviewed, evaluated, and updated several aspects of the work previously performed under the CAPP regarding potential small hydro development sites on the Klamath Project. The Team concluded that the Keno Dam site remains the preferred identified alternative for On-Project hydro generation development, due largely to the year-round flows available at the particular site which result in an annual generation capacity factor of approximately 82.5%. This is in comparison to capacity factors ranging from 60% to 82.5% for the other alternatives considered in the CAPP. The Team therefore selected hydropower generation development at Keno Dam to be the preferred alternative under this APM although other sites may be cost-effective as well.

There are multiple alternatives regarding the potential disposition of the energy and capacity to be generated by a new small hydro facility at Keno Dam and at other sites located on the Project. In addition, there are also several mechanisms by which water users receive the associated benefits. This topic is discussed in more detail later in this Chapter.

The installation of low-head hydro at existing facilities such as Keno Dam could tie into existing distribution lines, potentially lowering interconnection costs. Overall project costs could be reduced by using and refurbishing existing facilities (Eastside and Westside powerhouses). In addition, certain hydropower projects can seek an exemption from Federal Energy Regulatory Commission ("FERC") licensing requirements. Exemptions are available if a generating facility is under 10 MW and built at an existing dam, or is under 40 MW and constructed on an existing conduit primarily to serve purposes other than power production, such as irrigation.[63] FERC, however, does not have jurisdiction over Federally-owned hydropower projects.

Potential Challenges

Potential barriers to development of low-head hydro in the Klamath Basin include capacity size limitations due to geography, limited generation potential due to seasonal versus year-round flows, transmission of generated power, and environmental impacts. Current regulatory policies in both

[63] All the sites identified on the Klamath Project to date for potential hydro development would result in generating facilities smaller than 10 MW.

states limit the maximum generating capacity of renewable energy facility to no more than 80,000 kilowatts (kW) to be considered as a Qualifying Facility. To be considered as a Qualifying Facility, a hydropower facility requiring a new diversion must demonstrate that there is no adverse effect on the environment, including recreation and water quality, pursuant to Title 18 of the Code of Federal Regulations (CFR) §292.208.

New hydro generation facilities in the Klamath Basin must be interconnected to new or existing distribution or transmission lines. In general, interconnection costs depend on the project size and the length of the required interconnection line. These costs could make a project infeasible as the locations of many low-head hydro projects are often remote from loads, requiring longer transmission and distribution lines to connect to the local utility's power grid.

Generation development at Keno Dam and Eastside and Westside powerhouses would require consultation with the United States Fish and Wildlife Service and the National Marine Fisheries Service over Endangered Species Act-listed suckers and coho salmon. Also, future operations and the durability of low-head hydro development at these sites could be affected by changes to the existing biological opinions and the potential for anadromous fish passage following the removal of PacifiCorp's existing dams located on the Klamath River downstream of the Project.

In addition, water is typically available in many canals and conduits for only seven months out of the year, which acts to increase the cost per kilowatt-hour (kWh) generated and making it more difficult to recapture the initial capital costs. This limitation would not apply to Keno and Eastside/Westside.

Anticipated Net Power Cost Savings

Power cost savings from the potential development of small hydro generating plants in the Basin would likely flow directly to either Reclamation or to the irrigation districts who, in turn, could pass the dollar savings on to On-Project covered water users in the form of lower operation and maintenance charges. Potential power cost savings are primarily a function of the development and operating costs of the new hydro facilities versus the benefit of either displacing a portion of a water customer's power purchase costs from PacifiCorp or selling the generation output and using the net revenues received to offset their PacifiCorp power purchase costs.

Estimated Costs for New Hydroelectric Generating Plant Development

Capital development costs for generic, small hydroelectric generating plants are available from several different publicly available sources. In practice, however, the real-life capital costs associated with the development of small/low-head hydro plants can vary across a wide range depending upon multiple site-specific characteristics and the specific technologies to be employed. In addition, non-construction and equipment-related costs such as electric system interconnection costs, land costs, and environmental permitting are more difficult to quantify on a generic basis.

The *Capital Cost Review of Power Generation Technologies* (Western Electricity Coordinating Council) provides reviews of several technologies and is often cited to compare potential renewable power projects. From the 2014 version of this report, which was utilized in the CAPP analysis to evaluate the feasibility of small hydro plant development in the Klamath Project, the recommended capital development cost for small hydroelectric plants (unpowered dam, run-of-river plants at 26 MW or smaller with no major dam or diversion work) was $4,000/kW. The CAPP Study noted that development costs did not include the cost of interconnection, environmental permitting, or land costs.

In comparison, the Regional Hydropower Potential Scoping Study, which was prepared by the Northwest Hydroelectric Association and released in November 2014 estimated the capital costs of 13 new small northwest region hydroelectric generating plants with a benefit/cost ratio greater than 0.75 in the range of $1,889 to $5,075 per kW. The study cites that an average cost of $3,500 per kW installed is a representative cost figure for benchmarking new hydropower development on unpowered dams. In addition to capital costs, the study provided a range of operating costs for new 28 different units at unpowered dams. The average annual operating costs is 3% of the capital cost for these units.

In addition to unpowered dam hydro development, the Team also surveyed available literature and interviewed several developers who offer in-conduit technologies such as hydrokinetic systems to assess potential capital costs for this option. The Regional Hydropower Potential Scoping Study (Northwest Hydroelectric Association) cites an average cost range for in-conduit systems between $4,000 and $7,000 per kW. This figure is highly dependent on system configurations, existing infrastructure in place and the extent of civil engineering and development required for installation. The unit output of in-conduit units is generally considerably smaller than the generation capacity of units studied at the unpowered dams, making it more difficult to cost effectively generate energy at scale. These in-conduit units lend themselves primarily to serving local loads where the electrical interconnection is located behind the customer's meter with the local utility.

Given the capital costs for mid-sized hydroelectric plants installed on unpowered dams average around $3,500 per kW with an annual operations budget of around 3% of capital costs, the economic payback for plants is often built on an extended payback period – as long as 50 years for units in the 10 -30 MW range. If the power output from the hydro facility is sold to a third party in order to create a long-term revenue stream, the plant's developer would likely need to enter into a long-term power sales agreement of similar length with the purchaser in order to secure financing for the project.

Estimated Value of Power from a New Hydroelectric Generating Plan

There are several different mechanisms by which long-term revenue streams can be created from one or more low head hydro generating facilities to potentially be developed on the Klamath Project. In addition, the exact size and location of the hydro facilities are both key factors to maximize net benefits associated with the plants' generation output. For example, plants whose primary function is to help lower Reclamation's own Klamath Project pumping costs may likely be in different locations than plants whose primary purpose is to maximize net revenues under a wholesale power sales agreement. Several different potential mechanisms by which the output of one or more small hydro generating plants can be monetized are summarized below:

Federal Project-use Power Supply for the Klamath Project

A new hydro generating facility at Keno Dam (and potentially at other locations within the Klamath Project) could be incorporated into a newly formed Federal Project-Use Power supply for the Klamath Project. This topic is discussed in more detail in Chapter 14. Also, as is described in detail in the accompanying PCB Report, all five of the Reclamation projects that were identified as being Similarly Projects to the Klamath Project have access to Federal Project-use Power for the purpose of operating pumping or drainage facilities, or both, that are part of the Projects' water delivery infrastructure.[64]

Since power production is an authorized purpose of the Klamath Project, Reclamation has the ability to develop new sources of hydroelectric generation located at one or more points within the Project's boundaries. It should be noted that when the Project was originally being conceived and developed, Reclamation chose to purchase power from PacifiCorp under a 50-year agreement rather than develop its own power generation facilities to be located on the Project.

Sale to PacifiCorp under a Negotiated Rate

Power generated at Keno Dam or other hydro plants to be developed within the Klamath Project could be sold to PacifiCorp through a long-term power purchase agreement at negotiated rates. Such negotiated rates would, presumably, incorporate: 1) the full energy and capacity value of the generation produced at Keno Dam/other sites including potential locational benefits, and 2) the full value of the environmental attributes - such as renewable energy credits - associated with hydropower generation.

Sale to PacifiCorp under Avoided Cost Rates

Power generated at Keno Dam and other hydro plants could be sold to PacifiCorp through a standard-form power purchase agreement at PacifiCorp's avoided cost rates. The CAPP Report noted that PacifiCorp's 2015 avoided cost rates were 2.19 ¢/kWh and 2.77 ¢/kWh for off-peak and on-peak power deliveries, respectively. On-peak hours are Monday through Saturday from 6:00 am to 10:00 pm, excluding North American Electric Reliability Corporation (NERC) holidays, and off-peak hours are all other hours. It should be noted that PacifiCorp's standard avoided cost rates: 1) do not reflect the firm capacity value associated with generation at Keno Dam and potentially at other sites as well, and 2) do not fully value the environmental attributes of hydropower generation.

Sale to other Pacific Northwest Utilities under a Negotiated Rate

Although a generating plant located at Keno Dam or other sites on the Klamath Project would interconnect with PacifiCorp transmission/distribution facilities, power generated at the dam(s) could possibly be sold to other Pacific Northwest regional utilities through a long-term purchased power agreement at negotiated rates. Such negotiated rates would, presumably, incorporate: 1) the full energy and capacity value of the generation produced at Keno Dam/other sites including potential locational benefits, and 2) the full value of environmental attributes associated with hydropower generation.

Sales to utilities other than PacifiCorp, however, would be subject to additional transmission (and possibly distribution) costs associated with the wheeling of power across PacifiCorp's system to the purchasing utility. These additional delivery-related costs would need to be recovered through a higher sales price to the purchaser than what could be received by selling the power directly to PacifiCorp.

Sale to other PNW Utilities under Avoided Cost Rate(s)

Power generated at Keno Dam/other sites could be sold to Pacific Northwest utilities other than PacifiCorp through a standard form purchase power agreement at the purchasing utility's avoided

[64] In the Yakima Project, Reclamation does not receive Federal Project-use Power but one of the irrigation districts located with the Project (the Roza District) does.

cost rate. Since different electric utilities have established different sets of avoided cost rates, selling power to a utility other than PacifiCorp could result in a higher sales price. However, higher prices received from sales to other utilities may be partially, or even fully, offset by the additional transmission (and possibly distribution) costs associated with wheeling of power across PacifiCorp's system to the purchasing utility. In addition, other Pacific Northwest utilities' standard avoided cost rates: 1) may not reflect the firm capacity value associated with generation at Keno Dam/other sites, and 2) may not fully value the environmental attributes of hydropower generation.

Net Cost/Benefit Summary for Small Hydroelectric Plants

The APM Analysis Team performed two appraisal level LCOE analysis regarding the potential development of a 3.8 MW hydroelectric generating facility to be located at Keno Dam, as this was the preferred in-Basin small-hydro plant alternative identified in the earlier CAPP study. Both analyses incorporated the capital investment costs and first-year on-going O&M costs that were identified in the CAPP Report while using an assumed 50-year useful life of the generating facility. The Low Case LCOE analysis assumed a long-term annual discount rate of 1.0% and that O&M costs would escalate at a rate of 1.0% per year while the High Case LCOE analysis assumed a 3.0% discount rate with O&M costs escalating at 2.0 per year. The analysis also incorporated a 3% annual discount rate.

The resultant 50-year LCOE for the Keno Dam hydro facility in the Low Case was 4.695 ¢/kWh while in the High Case the LCOE was 6.787 ¢/kWh. In reviewing these results, the APM Analysis Team noted that although the Keno Dam site was identified as the preferred small hydro alternative in the CAPP Report, its per-unit capital investment cost of $9,447/kW is significantly higher than the benchmark estimated capital costs for the development of generic small-scale hydro plants located in the Pacific Northwest region (as discussed earlier in this Chapter). However, the cost estimate developed in the CAPP study for the Keno Dam alternative was an "all-in" figure that included not only the direct cost of the newly installed hydro generation equipment but also: 1) land acquisition costs, 2) permitting costs, and 3) the cost of the electrical interconnection.

Chapter 13 APM No. 7 - Purchases of Federal Power

Overview/General Information

When the Klamath Project was originally being developed in the early 1900's, Reclamation entered into a long-term power purchase arrangement with PacifiCorp to provide electricity needed by Reclamation and districts and water users to operate the Project at a negotiated rate in exchange for Reclamation allowing PacifiCorp to construct and operate Link River Dam. Later (in the 1950s) Reclamation effectively agreed to allow PacifiCorp to develop additional, valuable hydroelectric generation (J.C. Boyle, and later, Iron Gate) in exchange for continuation of a comparable negotiated rate. This arrangement was in contrast to many other irrigation projects that were being developed by Reclamation in the Pacific Northwest region around the same time whereby a portion of the electricity produced at dams being constructed by the Federal Government was dedicated to serving Reclamation's irrigation-related pumping loads.

Power produced at Federally owned facilities in the Pacific Northwest region that is utilized by Reclamation at Reclamation projects is commonly referred to as "Project-use Power" or "Federal Reserved Power". In some cases, hydroelectric generating facilities were developed as part of Reclamation's irrigation projects; in these cases, the power produced at these dams is first utilized to serve Reclamation's own project-level pumping loads with any excess power being sold by the Bonneville Power Administration ("BPA") to other customers.[65] Typically, BPA sells Project-use Power to Reclamation "at cost", that is the cost of producing power at the specific set of facilities that are incorporated into that particular Project-use Power pool.[66] In addition, a limited number of irrigation districts located within Reclamation projects are also eligible to purchase Project-use Power in order to operate their own district-level pumps.

For Reclamation irrigation projects in the Pacific Northwest that do not have a dedicated pool of associated hydroelectric generating facilities, Reclamation can still purchase wholesale power from BPA to operate those projects under what is known as the Pacific Northwest Generating Cooperative or PN rate. The PN rate is based upon the cost of owning and operating BPA's overall power resource portfolio, which consists primarily of hydroelectric generating facilities.[67]

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[65] BPA is one of four Federally owned Power Marketing Administrations that market wholesale power in the western portion of the United States. BPA markets wholesale power in the Pacific Northwest region to multiple different publicly owned and tribally owned utilities under cost-based rates. BPA also sells excess wholesale power supplies to multiple entities in the Northwest and California at market-based rates.

[66] For example, Reclamation's Boise, Minidoka, and Owyhee irrigation projects all purchase Project-use Power from BPA under what is referred to as the Southern Idaho Rate.

[67] BPA's overall power resource portfolio is commonly referred to as the Federal Columbia River Power System (FCRPS).

Historically, purchasing power from BPA at the PN rate has allowed Reclamation to operate its project-related pumping facilities at a lower overall cost than purchasing power from local electric utilities. Most of the publicly owned electric utilities located in the Pacific Northwest region such as municipalities, public utility districts, and cooperatives, also purchase power from BPA under a similar cost-based rate referred to as the Priority Firm or PF rate.

Therefore, an opportunity may exist for Reclamation to reduce its power costs for operating the Klamath Project by replacing the power it currently purchases from PacifiCorp with a new wholesale power supply from BPA under either the existing PN rate or potentially under a new Project-use Power rate to be specifically established for the Klamath Project.[68]

Potential Benefits

- On-Project covered water users could receive indirect benefits from Reclamation's purchase of Federal power via a reduction in operation and maintenance charges to be assessed to the irrigation districts that serve these customers.
- Since the majority of Reclamation's power loads are located in Oregon, On-Project covered water users located in the California portion of the Klamath Project may still receive indirect benefits via lower water delivery rates being assessed by Reclamation to their local irrigation districts.
- Reclamation's purchase of Federal power from BPA at the PN Rate would not require the development of any new generating resources, either inside of or outside of the Upper Klamath Basin. PN Rate power would be supplied by BPA out of its existing resource portfolio.
- It is possible that new Federally owned generating facilities could be developed in order to form a new Klamath Project-use Power portfolio that has a lower overall generating cost than the Federal Columbia River Power System (FCRPS). This would act to reduce Reclamation's overall power purchase costs to a greater degree as compared to it purchasing power from BPA under its standard PN Rate.

Potential Challenges

The primary challenges facing this APM are:

- The expected net benefit resulting from this APM are primarily a function of the differential between Reclamation's cost of purchasing wholesale power from a Federal supply and having that power delivered to Reclamation's Klamath Project pumping loads versus purchasing an equivalent amount of power from PacifiCorp under its retail irrigation rate

[68] It should be noted that even if Reclamation (and possibly some of the irrigation districts) were to purchase wholesale power from BPA, individual on-farm water users would still purchase their power supplies from PacifiCorp pursuant to PacifiCorp's retail rate tariffs in effect in Oregon and California.

tariff(s). The costs for both of these power supply alternatives are subject to change across time.

- Although BPA has transmission facilities that run through the Upper Klamath Basin and are in relatively close proximity to some of Reclamation's irrigation pumping loads, absent the construction of new BPA or Reclamation-owned transmission and distribution lines, Federal power would need to be transmitted across PacifiCorp owned-lines in order to be delivered to Reclamation's loads. While the costs associated with wheeling Federal power across PacifiCorp's transmission system can presently be reasonably quantified, the additional costs associated with wheeling power across portions of PacifiCorp's local distribution facilities are not presently known.[69]
- This APM could not be utilized by individual water users to replace the power they are currently purchasing from PacifiCorp with a new Federal or Project-use Power supply. On-Project covered users could still receive a benefit, however, in the form of lower operation and maintenance charges from Reclamation and the local irrigation districts. However, it is not clear how Off-Project covered water-users could receive benefits under this APM.
- The creation of a new Klamath Project Project-use Power portfolio, consisting of a yet-to-be determined pool of new generating resources, could involve a significant amount of time and effort on Reclamation's part.[70]
- Federal power produced in the Pacific Northwest region probably could not be provided by BPA to water users located in the California portion of the Project, however, it may be possible for these users to receive Federal Klamath Project-use Power (likely from the Western Area Power Administration or WAPA) from facilities developed within California.

Anticipated Net Power Cost Savings

The potential power cost savings associated with Reclamation, and potentially some of the irrigation districts in the Project as well, purchasing Federally-produced wholesale power from BPA are primarily a function of three key drivers: 1) the base cost of the wholesale power purchased from BPA, 2) the transmission and distribution costs associated with delivering Federal power to Reclamation's pumping loads in the Upper Klamath Basin, and 3) the estimated costs of Reclamation continuing to purchase power from PacifiCorp under its retail irrigation rate tariffs.

Reclamation's ability to economically purchase Federal Project-use-Power from BPA under BPA's current PF rate is considerably hampered by the fact that Reclamation's pumping loads in the Klamath Project are all interconnected to PacifiCorp's power system at voltages of 2,300 volts or less. This situation means that wholesale power delivered by BPA to Reclamation's pumping loads in the Basin would be subject to both PacifiCorp's transmission and distribution tariff charges. Under PacifiCorp's currently-in-effect Oregon Schedule 741 open access irrigation rate tariff, the sum total of the cost for Reclamation to purchase wholesale power from BPA under the current PF rate and

[69] All of Reclamation's pumping loads located in the Klamath Project are presently interconnected to PacifiCorp's system at voltages of 2,300 volts or less. Therefore, some portion of PacifiCorp's lower-voltage distribution system would need to be utilized to deliver Federal power to Reclamation's loads.
[70] According to information provided by Reclamation and reviewed by the APM Analysis Team, power is an authorized use of the Klamath Project.

transmit that power across PacifiCorp's transmission and distribution facilities would exceed the energy price that Reclamation pays to PacifiCorp under Schedule 741.

However, if Reclamation were to develop a new source of Project-use Power to serve its loads in the Upper Klamath Basin using a set of (presumably renewable) resources to be located within the Basin itself, overall power cost savings may be achievable if Reclamation could negotiate some form of short-distance transmission/distribution wheeling rate discount with PacifiCorp that results in lower overall delivery costs than what are presently incorporated into PacifiCorp's Schedule 741 retail open-access tariff.

Chapter 14 APM No. 8 - Open-Access Power Purchases

Overview/General Information

Retail electricity customers located in Oregon have an option to purchase power from entities other than their local utility provider under what is referred to as "open access" programs. Irrigation customers served by PacifiCorp in Oregon can voluntarily elect to purchase power pursuant to PacifiCorp's existing Open Access Tariff which is Schedule 741. PacifiCorp currently does not have an open access program in place for irrigation customers located in California.

Under PacifiCorp's Schedule 741, customers choose their own third-party power supplier and PacifiCorp then transmits the power across its transmission and distribution facilities to the customer. Since it may be difficult for smaller power users to arrange a wholesale power supply on their own, entities known as "retail aggregators" often act as an intermediary in the open access process. Retail aggregators act to combine the power needs of a large group of individual end-use customers and then market the combined load pool to different wholesale power suppliers. In this fashion, small power users can often receive a lower price by being part of a larger "buying" pool. In addition, the aggregator handles many of the administrative functions needed to implement the wholesale power purchases for the entire load pool.

Potential Benefits

PacifiCorp's Schedule 741 allows end-use irrigation customers to replace the power supply component of PacifiCorp's fully bundled retail rates (i.e. Schedule 41) with power supplies obtained by other regional suppliers. Depending upon prevailing wholesale power market conditions, the size and shape of the customer's load, and the length of time that the customer is willing to commit to an alternate power supply source, the customer may be able to moderately reduce their overall power costs by utilizing Schedule 741. The customer can also choose to utilize the services of a retail aggregator, which may result in lower power supply costs to the customer through economies of scale.

Electing to take service under Schedule 741 is one of the APM alternatives that can be implemented both relatively quickly and with minimal startup costs (other than time and effort on the part of the customer to contact potential suppliers or retail aggregators). If irrigation customers arrange their power purchasers through a retail aggregator, the aggregator will perform many of the administrative functions required to effectuate the delivery of the wholesale power supply (on behalf the customer) to PacifiCorp.

Potential Challenges

An important feature of the Schedule 741 open access program is that it is not possible to bypass PacifiCorp's transmission and distribution charges; this remains the case whether or not a customer arranges for their own wholesale power supply or utilizes the services of a retail aggregator. Therefore, the maximum savings that an end-use customer can receive under the open access program is the difference between PacifiCorp's own power supply cost as specified in Schedule 741 and the cost of acquiring power supplies on the open market from other entities.

Currently, Schedule 741's power supply component is between approximately 3.1 - 3.2 ¢/kWh.[71] Therefore, an end-use customer would need to locate and acquire, either on their own or through a retail aggregator, power supplies from a non-PacifiCorp entity at a lower price in order reduce their overall power purchase costs. However, since customers cannot avoid paying PacifiCorp's transmission, distribution, and "base" power supply related costs (which make up approximately 65% of an irrigation customer's overall cost of power during the summer months), the maximum potential savings that customers can achieve by taking service under the open access program are considerably reduced into a fairly narrow range.

While end-use PacifiCorp irrigation customers have an opportunity to reduce their overall power costs by voluntarily taking service under Schedule 741, such savings are not guaranteed. Depending upon the specific terms and conditions that apply to a customer's power purchase made from a non-PacifiCorp entity, the customer's overall total power costs could be higher than what they would have paid under PacifiCorp's standard Schedule 41 irrigation tariff. In addition, short-term wholesale power prices in the Pacific Northwest tend to be very volatile; customers therefore need to be aware that when they commit to a purchase at a specific price for a specified time period with a third-party power supplier or retail aggregator, there is no guarantee that the price will remain the same for a future purchase period.

Another potential challenge is that irrigation-related loads are very seasonal in nature and, in addition, can vary due to prevailing weather conditions. These load characteristics are somewhat unfavorable to potential alternative power suppliers who generally favor loads that are relatively constant across time. The seasonality and potential variability of irrigation loads will likely result in irrigation customers paying a higher rate for their power supplies from a third-party seller or aggregator as compared to customers that have steady loads throughout the year (for example a data center).

Customers that voluntarily choose to take service under Schedule 741 are required to enter into a written contract with PacifiCorp for a term of not less than three years. The ability of a customer to switch back to standard, fully bundled service (such as Schedule 41 for irrigation customers), and the timing of such change, would be subject to the specific terms and conditions contained in its contract with PacifiCorp.

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71 These figures are based upon PacifiCorp's Schedule 741 Price Summary dated January 1, 2020.

Anticipated Net Power Cost Savings

It is important to stress that while use of PacifiCorp's Schedule 741 provides an opportunity for an end-use irrigation customer to lower their overall power costs, such savings are not guaranteed. In particular, short-term wholesale power prices in the Pacific Northwest region can be very volatile, especially during periods of high-power demand (which, unfortunately, can occur during the summer months when irrigation water use is also high). In the longer-term, wholesale power prices are driven by a variety of factors such as natural gas prices, river flows at regional hydroelectric plants, and Greenhouse Gas regulations that are difficult to predict and beyond the control of end-use customers.

The above factors act to create an additional degree of risk for end-use irrigation customers that choose to purchase their power supplies under Schedule 741 as compared to purchasing power from PacifiCorp at a known cost under Schedule 41. While some of these risks can reasonably be managed or reduced (for example, by agreeing to purchase wholesale power from an alternate supplier at a fixed and known price across a pre-specified time period), other potential risks may be more difficult to mitigate. Helping to counteract these risks, however, is the ability of irrigation customers to return to receiving service from PacifiCorp under Schedule 41, subject to the timing provisions specified in their contracts with PacifiCorp.

Given current estimates of wholesale power prices in the Pacific Northwest region during calendar Year 2020, there appears to be, at best, only a small differential between the market price for wholesale power supplies delivered to the Mid-Columbia ("Mid-C") or the California-Oregon Border ("COB") delivery points and the 3.1 – 3.2 ¢/kWh displaceable power supply cost that is incorporated into PacifiCorp's Schedule 741. The maximum near-term cost savings available to irrigation customers under Schedule 741 are forecasted to be only in the range of 4.0 – 5.0% of the customer's summer month power costs. Given these conditions, the opportunity to utilize this APM to create meaningful power cost reductions for water users in the Upper Klamath Basin appears to be extremely limited.[72]

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[72] It should be noted that power prices quoted by potential power suppliers or retail aggregators to individual irrigation customers are likely to be somewhat higher than wholesale market price quotes at the Mid-C and COB; these prices are referenced to fixed 25 MW blocks of wholesale power to be delivered across all 24 hours of the day, seven days a week. This condition further limits potential power cost savings under this APM, which are already projected to be quite low.

Chapter 15 APM NO. 9 - PacifiCorp Irrigation Customer Cost-of-Service Evaluation

Overview/General Information

The retail power rates that PacifiCorp charges to irrigation customers (including Reclamation) are subject to the jurisdiction of the OPUC and the CPUC. When PacifiCorp proposes to make changes to its retail rates that are currently in effect, it generally does so through one of two regulatory processes; 1) filing a new General Rate Case ("GRC"), and 2) filing a new Power Cost Adjustment Case. These two rate-making processes are discussed in more detail in the following two Sub-chapters.

General Rate Cases

When PacifiCorp desires to change one or more of its retail rates that are currently in effect and these changes involve issues other than just power supply-related costs, it will file what is referred to as a GRC. General Rate Cases (GRCs) are usually complex processes that are broad in scope and entail large volumes of supporting documentation from the utility requesting the change in rates. GRCs usually follow a very regimented process that allows for a considerable degree of public stakeholder involvement. Due to the complexity of these cases and the sheer volume of materials to be evaluated by the state rate commissions and stakeholders, it is common for GRCs (including PacifiCorp's) to take up to approximately one year to complete.

GRCs provide an opportunity for affected customers (or organizations that represent one or more groups of customers) to analyze and challenge the multiple inputs, assumptions, and calculations that impact the final sets of rates. Customers can also propose alternative approaches for consideration by the rate commissions that may result in lower rates than those proposed by the utility.[73]

General Rate Cases generally include what is referred to as a Cost-of-Service Analysis ("COSA"). In a COSA, the utility determines its cost to serve each of its individual rate classes, which usually includes an irrigation customer class. While some utility costs can be directly assigned to a particular customer class - for example a new substation constructed specifically to serve one or more new large industrial power users located in a specific area - many of a utility's costs support multiple

[73] It is noted that for many decades water users in the Upper Klamath Basin had no interest or need in being active participants in PacifiCorp's retail rate tariff setting processes since they were purchasing power under a separate set of terms and conditions as specified in the 1917 and 1956 power purchase agreements. However, now that Reclamation, irrigation districts and covered water users in the Basin are all purchasing power from PacifiCorp under standard irrigation/drainage retail rate tariffs, these stakeholders now have a vested interest in working with PacifiCorp, the Oregon and California Rate Commissions, and other stakeholders to ensure that PacifiCorp's rates are just and reasonable.

different customer classes (for example the costs associated with the utility's main office buildings and support staff).

A utility's shared costs are usually allocated among each of the individual customer classes using what is referred to as the "cost causation principle." Allocating these shared costs to individual customer classes – which ultimately feed into the individual retail rates – is an involved process that usually entails multiple different allocation mechanisms and assumptions. It is not uncommon for customers or other stakeholders to question the results of the utility's COSA in a GRC and to present alternative sets of cost allocations and associated retail rates for consideration by the state rate commissions.

Due to the natural conflicts present between electric utilities who generally desire to increase retail rates, and customers/stakeholder groups who likely prefer rate decreases, many GRCs are highly contested processes that are ultimately concluded through settlement agreements between the utility, stakeholders, and the state rate commission staffs. Once the state rate commission approves a settlement agreement, or in the absence of a settlement agreement comes to its own conclusions, a set of "Base Rates" are established for all retail customer classes. These Base Rates remain in effect until: 1) the utility files a new GRC, and 2) the appropriate rate commission approves a new set of retail rates.

Power Cost Adjustment Cases

One of the major components of PacifiCorp's retail power rates in both Oregon and California is its cost of generating electricity from power plants that it owns and purchasing wholesale power supplies in the Pacific Northwest and California markets as needed to meet its overall load obligations. These power supply related costs are subject to multiple different factors that can cause these costs to be either higher than, or lower than, the assumed level of costs that were incorporated into the Base Rates established in its last approved GRC filings.

The Power Cost Adjustment rate processes in place in Oregon and California allow PacifiCorp to pass through many "normal" variations in power supply costs to its retail customers on a regular basis without the utility having to file a GRC (which usually is much broader in scope than a power cost adjustment process). In a Power Cost Adjustment process, many elements that would normally be subject to review in a GRC are left unchanged. PacifiCorp's power cost adjustments are shown on retail customers' bills in both Oregon and California and, can either be an additional charge that acts to increase a customer's overall power costs relative to the Base Rates, or act as a credit to decrease a customer's power costs.

Potential Benefits

PacifiCorp's last GRC in Oregon took place in 2013 and PacifiCorp filed its last GRC in California in 2019. Unlike the power cost adjustment cases that follow a regular, pre-defined schedule, there currently is no regular schedule for when PacifiCorp is required to file GRCs in either state. In addition, if PacifiCorp decides to file a new General Rate Case in one state, it does not necessarily have to file a new GRC in the other state at the same time (although it could choose to do so).

In reviewing portions of PacifiCorp's last retail rate cases filed in Oregon and California, the APM Analysis Team believes that opportunities exist for stakeholders that have an interest in irrigation power rates - including Reclamation, irrigation districts, individual customers, and irrigation stakeholder groups - to actively participate in PacifiCorp's next set of GRCs to attempt to reduce power costs to water users in the Upper Klamath Basin in several ways.

For example, many of PacifiCorp's general costs of doing business cannot be directly assigned to one or more specific customer groups – rather these costs are distributed across the different retail rates classes using multiple different allocation factors. In particular, Administrative and General costs and Operations and Maintenance costs are two large categories of PacifiCorp's costs that should be closely inspected in a GRC setting to ensure that excess costs are not being allocated to PacifiCorp's irrigation rates as compared to its actual costs of providing power to water users located in the Upper Klamath Basin.

With regard to the allocation of PacifiCorp's transmission and distribution related costs, it should be noted that the California portion of the Basin has a relatively high concentration of irrigation loads as compared to PacifiCorp's other agricultural loads that are located within its northern California service territory (which tend to be more physically dispersed). Likewise, in Oregon, distribution infrastructure (and perhaps some transmission infrastructure as well) that PacifiCorp has developed for the purpose of serving end-use agricultural loads in areas located outside the Upper Klamath Basin is obviously not utilized to serve irrigation loads located within the Basin. These are examples of the types of items that Reclamation, stakeholder groups, and individual water users should consider carefully evaluating, and if appropriate make alternate cost allocation proposals, as part of PacifiCorp's future GRC proceedings.

An opportunity exists for Upper Klamath Basin stakeholders to work with PacifiCorp and the Oregon and California Rate Commissions to re-design irrigation retail rates to better reflect PacifiCorp's actual costs of providing electric service in the Basin. While the exact outcome of such actions in helping to reduce power costs in the Basin cannot be predicted at present due to multiple factors – including the willingness of the state rate commissions to support an irrigation rate re-design – there nevertheless appears to be limited downside for Reclamation and stakeholders in exploring such options.

Potential Challenges

There are few downsides to irrigation customers and stakeholder groups being more highly involved in PacifiCorp's rate setting processes with the primary investment costs being in the form of time and effort. Given the potential benefits in the form of reduced power rates for some, or perhaps all irrigation customers located in the Upper Klamath Basin, there appears to be minimal risk in being active participants in these processes.

One potential challenge to be navigated is the uncertain timing regarding future PacifiCorp GRCs in Oregon and California. While PacifiCorp's Power Cost Adjustment cases are filed pursuant to a predictable annual schedule, GRCs are not. Instead, GRC processes are generally initiated at PacifiCorp's discretion and at irregular intervals.[74] Because the annual Power Cost Adjustment filings only address a pre-determined and limited set of the full universe of potential retail rate issues,

[74] For example, PacifiCorp's last general rate case in Oregon took place in 2013.

irrigation customers and stakeholders may need to wait until PacifiCorp's next Oregon or California GRC proceedings in order to address certain topics of importance.

Also, irrigation customers and stakeholders should note that both of PacifiCorp's retail rate setting processes are conducted pursuant to very structured and formal regulatory requirements that have been established by the two rate commissions. It is therefore important that customers and stakeholder groups become familiar with each rate case's schedule and be prepared to attend open hearings on the indicated dates and submit written comments by the established deadlines. Failure to abide by the formal schedules established by the Oregon and California Rate Commissions may result in lost opportunities for irrigation customers and stakeholders to present their positions and have their voices heard.

Anticipated Net Power Cost Savings

It is difficult at the present time to estimate the potential power cost savings associated with irrigation stakeholders located in the Upper Klamath Basin (including Reclamation, irrigation districts, water user groups and individual on-farm users) becoming more active participants in PacifiCorp's retail rate setting processes. In general, power cost savings may be achievable by working with PacifiCorp, the state rate commissions, and other stakeholders with the goal of modifying PacifiCorp's current Schedule 41 and Schedule PA-20 irrigation rate tariffs to incorporate some form of reduced charges. Such reductions might be achieved via the cost re-allocation review process described above, or by the Oregon or California Rate Commissions agreeing to establish PacifiCorp's irrigation rates at below cost-of-service levels as a matter of public policy that takes into account the importance of healthy agricultural communities to the public's overall well-being.

Chapter 16 APM Implementation Summary

Overview

The nine APMs discussed in detail in Chapters 7-15 cover a broad range of potential mechanisms that can be implemented in order to help reduce power costs for water users in the Upper Klamath Basin. An important feature of this suite of cost-reduction measures is that many of the APMs can be implemented in a concurrent fashion or in different combinations that best fit the needs of individual water users. While it is true that some of the APMs may not be available and/or provide an equal level of benefits to all covered water users in the Basin, the APM Analysis Team attempted to identify and evaluate the APMs so that Reclamation, irrigation districts, and individual covered water users would all have multiple viable power cost alternatives available for consideration.

An important feature of the identified APMs is the question of who can implement the measures. For example, some of the APMs would either need to be, or could be, implemented by Reclamation, with the associated power cost reduction benefits flowing down to individual On-Project covered users via lower operation and maintenance charges. In other cases, individual On-Project and Off-Project cover users could choose to implement one or more APM's with the associated benefits accruing solely to themselves.

Table 16-1 summarizes the nine APMs along with information regarding how the measures could be implemented.

High Priority Affordable Power Measures

Based on an overall evaluation of each APM, six Measures were identified as exhibiting the best balance between: 1) a reasonable expectation of meaningful power cost reductions, 2) an ability to implement the Measure in a realistic timeframe, and 3) a widespread distribution of benefits across multiple categories of water users in the Basin. These High Priority Measures are listed in Table 16-2.

Table 16-1. APM Implementation Summary

APM No.	Affordable Power Measure	Who Implements the Measure?	How is the Measure Implemented?	Time Horizon For Implementation	Distribution of Benefits
1	Solar PV Development Alternative 1 - (small facilities)	Individual power customer	Individual customer installs solar PV facility	Weeks to months	Individual water user or groups of water users
1	Solar PV Development Alternative 2 – (shared facilities)	Groups of power customers under a central coordinating entity	Individual power customer decision with central entity installing solar PV facility	12 – 24 months	Groups of Off-Project or On-Project water users
1	Solar PV Development Alternative 3 – (grid scale facilities)	A central developer and a central benefits administrator	Developer commits to develop solar PV facility	24-36 Months	Developer enters arrangement with group(s) of water users
2	Net Metering	Individual power customers	Customer signs up with PacifiCorp	1-2 Months	Individual water users who have self-generation
3	Out-of-Basin Renewable Investment	A central developer and a central benefits administrator	Developer commits to invest in a renewable energy project	24-36 Months	Developer enters arrangement with group(s) water users
4	Time-of-use Power Rates	Individual power customers	Customer signs up with PacifiCorp	TBD based on post-pilot program terms and conditions	Individual water user or groups of On-Project water users

5	Irrigation Load Control Programs	Individual power customers	Customer signs up with PacifiCorp	TBD based on post-pilot program terms and conditions	Individual water users or groups of On-Project water users
6	Small Hydro Plant Development	Reclamation or irrigation districts	Developer commits to construct hydro facility	3-5 Years	On-Project water users
7	Purchases of Federal Power	Reclamation	Reclamation develops a new Federal power supply portfolio	2-5 Year	On-Project water users
8	Open-access Power Purchases	Individual power customers	Customer signs up with PacifiCorp and commits to an alternative power supply	Months	Individual water users
9	PacifiCorp Irrigation Cost of Service Evaluation	Individual or group(s) of power customers	Active participation in PacifiCorp rate setting processes in OR and CA	Ongoing with initial action in months	All water users

Note to Table 16-1:
An "Individual Power Customer" can refer to: 1) Reclamation, 2) an irrigation district, 3) an On-Project water user, or 4) an Off-Project water user. Power cost benefits associated with measures implemented by an individual On-Project or Off-Project water would be directly conveyed to that specific user while measures implemented by Reclamation or irrigation districts would be conveyed (indirectly) to On-Project users, generally via lower operation and maintenance charges.

Table 16-2. High Priority Affordable Power Measures

APM No.	Affordable Power Measure	Federal Study Potential
1	Solar PV Development – Alternative 1 (individual facilities)	Yes
1	Solar PV Development – Alternative 2 (shared/community-scale)	Yes
1	Solar PV Development – Alternative 3 (grid-scale)	Yes
2	Net Metering (used in conjunction with Solar PV Alternatives 1 & 2)	Yes (See Note 1)
4	Time-of-Use Power Rates	(See Note 2)
5	Irrigation Load-Control Programs	(See Note 2)
9	PacifiCorp Irrigation Cost-of-Service Evaluation	No

Note 1: This item correlates with Action Item 2 in Chapter 21

Note 2: To the extent that implementation of these APMs by Reclamation or irrigation districts causes negative impacts to other water users in the Upper Klamath Basin, Federal Funding might be utilized to either: 1) provide financial offsets to the affected users, or 2) develop additional water system infrastructure to directly reduce the negative water delivery/timing impacts.

Chapter 17 - Equipment/Efficiency Upgrades

Overview/General Information

The water delivery and return systems that were developed by Reclamation and irrigation districts in the Klamath Project were specifically designed around low-cost supplies of power. This is due primarily to local geography and especially since the Project has a relatively large amount of drainage related pumping load as compared to other similarly situated Reclamation projects located in the Pacific Northwest region. In addition, Off-Project covered water users located in the Upper Klamath Basin, and some On-Project users as well, rely upon deep well pumping to irrigate their crops, which is also an energy intensive operation.

Given the large amount of irrigation pumping loads in the Klamath Basin and the associated on-farm water delivery equipment (such as irrigation pivot sprinklers), opportunities exist in the Basin to upgrade or potentially replace existing water delivery components to use more energy efficient equipment and thereby reduce overall irrigation electricity consumption. In addition, energy efficiency and equipment improvements are specifically referenced in the AWIA as a potential mechanism to reduce power costs in the Basin.[75] Although not considered to be an APM, Equipment/Efficiency Upgrades were considered to be an additional potential power cost solution for covered water users in the Basin; therefore, these types of upgrades were also researched by the APM Analysis Team.[76]

Potential Benefits

In 2014, Reclamation conducted pump efficiency and energy consumption testing on several of the Reserved and Transferred Works ("R&T Works") facilities and private pumps to assess general equipment conditions and to undertake specific efficiency testing. The testing found that annual energy consumption could be reduced at many R&T Works facilities and private pumps through pump and motor upgrades and reoperation. In addition, improvements to existing equipment could leverage funds available through current PacifiCorp, the Natural Resources Conservation Service's (NRCS) Environmental Quality Incentives Program (EQIP) and Energy Trust of Oregon ("Energy Trust") energy efficiency programs in Oregon.

One specific EQIP example is a cost-shared project with the West Cache Irrigation Company, located in northern Utah. The irrigation company combined $400,000 of federal funding with $520,000 of its own funding to convert over 2 miles of earthen canal to a pressurized pipe system.

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[75] https://www.congress.gov/115/bills/s3021/BILLS-115s3021enr.pdf

[76] Since Equipment/Efficiency upgrades were not considered to be an APM, the APM Analysis Team did not perform cost/benefit analyses on the universe of possible upgrades. However, several key findings from the CAPP Report are summarized in this Report in order to assist water users in evaluating the potential benefits associated with equipment efficiency upgrades aside the identified APMs.

This example reflects the dual benefit realized of not only conserving water, but also reducing energy consumption. By converting to a pressure delivery system, more water is conserved by eliminating evaporation losses and canal leaks, and less pump energy is required for irrigating at the farm.

General benefits to water users in the Upper Klamath Basin of implementing irrigation system energy efficiency improvements in the On-Project and Off-Project portions of the Basin include the following:

- Irrigation districts and individual on-farm water users can voluntarily choose to reduce their power costs by making cost-effective investments in more energy-efficient equipment (which results in directly reducing overall electricity usage).
- Expected power cost savings and the associated payback period can reasonably be determined at the time of the energy efficiency investment.
- Several organizations, including NRCS and Reclamation, have existing programs to assist agricultural water users: 1) identify equipment to potentially be upgraded/replaced, 2) perform cost/benefit analyses, and in some cases 3) provide financial assistance/grants to help defray some of the customer's up-front investment costs. Several of the organizations that provide these types of services to agricultural water users are listed in Appendix E.

Potential Challenges

The main constraint associated with efficiency and equipment improvements on the irrigation systems located in the Upper Klamath Basin is funding. Replacing or upgrading older, inefficient irrigation-related equipment usually requires a significant up-front investment with the associated benefits accruing back to the investor over a fairly long period of time. In addition, it is likely that some covered water users in the Basin have more opportunities available (for various reasons) to make cost-effective investments in energy efficiency than other users. Also, some funding programs that are available to assist water users in reducing their up-front energy efficiency investment costs have been established on the state level; therefore, some of the potential funding sources available to covered users located in the Oregon portion of the Basin are not available to users located in California.

Anticipated Net Power Cost Savings

Potential gross cost savings for power use associated with energy efficiency upgrades are primarily a function of: 1) the efficiency differential between the new equipment and the old equipment to be replaced, 2) how often the equipment is expected to be operated, and 3) the estimated future cost of electricity. In general, efficiency improvements provide an excellent opportunity to reduce power costs if the currently installed equipment is of an older vintage.

In the Upper Klamath Basin, strategic equipment replacements could be undertaken to assist in maximizing energy savings at private pumps and select R&T Works facilities. The field testing performed by Reclamation in 2014 found that annual energy consumption could be reduced by 9 to

30 percent at R&T Works facilities and 12 to 30 percent at private pumping facilities through pump upgrades and reoperation (e.g., operating a more efficient pump more frequently than a less efficient pump).

Funding, in the form of incentives provided through the Energy Trust of Oregon as another example, could be leveraged to help reduce the up-front expenses associated with implementing energy efficiency improvements in the Oregon portion of the Klamath Basin. Currently, Energy Trust offers PacifiCorp customers in Oregon rebates on irrigation equipment and incentives for pump and irrigation system upgrades, as shown in Table 17-1 below.

Table 17-1. Energy Trust Energy Efficiency Incentives for OR PacifiCorp Customers

Type	Incentive
Cash incentives for irrigation equipment	Linear and pivot improvement: $5 per low-pressure regulator $4 per rotating-type sprinkler that replaces an impact sprinkler $2.75 per sprinkler for new multiple configuration nozzles Wheel and hand-line improvement: $10 per section of cut and pipe press repair of leaking pipes $3.75 per flow controlling type nozzle for impact sprinklers $2.00 per new gasket, including mainline valve gaskets and mainline section gaskets
Custom cash incentives	Up to 40 percent savings for drip irrigation system conversion Up to 50 percent energy savings for existing pump or linear/pivot system conversions
Scientific irrigation scheduling	$3.22 per irrigated acre, up to 100 percent of the cost of the service or equipment for as many as three years.[1]

Values listed in this table are subject to change throughout the year. Visit the Energy Trust website: https://www.energytrust.org/ for the full list of the most up-to-date offers.

[1] Incentive is paid at the end of the growing season.

Chapter 18 Risks and Uncertainties

Overview

This report chapter summarizes several of the more prominent risks and uncertainties associated with the future cost of power for irrigation and drainage in the Upper Klamath Basin along with potential risks in implementing the identified APMs. In addition, some initial observations regarding how such risks might be managed or at least partially mitigated by Reclamation, irrigation districts, and individual water users in the Upper Klamath Basin are discussed as well.

PacifiCorp Retail Electric Tariff Price Risk

First, it is important for agricultural water users/power users in the Basin to recognize that the risks associated with implementing one or more of the APMs should be evaluated relative to the status quo. This implies that water users would continue to purchase all their power supplies from PacifiCorp under full retail rates. This baseline alternative, the "do nothing" approach, contains several inherent risks as well. For example, PacifiCorp's retail irrigation tariffs in Oregon and California already contain power cost adjustment clauses that allow PacifiCorp to pass through the impacts of a wide variety of risks and uncertainties to their electric customers. Some examples of these risks include changing streamflow conditions, changes in natural gas prices, and changes in regulatory or environmental policies that impact the operation of PacifiCorp's fleet of generating plants. PacifiCorp can pass through the economic impacts of these multiple uncertainties to its power customers (in the form of rate surcharges or credits) on an annual basis pursuant to the cost adjustment procedures that have been approved by the Oregon and California Rate Commissions.

In addition, PacifiCorp can file a GRC with the Rate Commissions at virtually any time, under which the company can request a wider set of changes to rates that what is allowed under the more streamlined power cost adjustment mechanisms. Again, while any rate increases that may result from a GRC process are subject to the approval of the OPUC or the CPUC, or both, the key point is that retail prices for electricity during the last several decades in the PNW have, in general, tended to increase across time rather than decrease. Therefore, when evaluating the mid-to-long term costs and benefits of any of the APMs or potential energy efficiency upgrades, it is important to recognize that the comparison yardstick – PacifiCorp's retail irrigation/drainage rates – will not remain constant in the future.

Therefore, as Reclamation, irrigation districts and individual water users move forward to conduct next-level feasibility analyses on the identified high priority APMs as discussed in Chapter 21, it is imperative that these analyses incorporate multiple sensitivity scenarios that include potential future impacts on, and changes to, PacifiCorp's retail irrigation rate tariffs in place in Oregon and California. This is an especially timely issue given that PacifiCorp recently announced that it would be retiring several more of its coal-fired power plants and replacing this lost capacity and energy with approximately 800 MW new renewable generating plants. This large shift in PacifiCorp's power generation mix will undoubtedly have a reasonably significant impact on PacifiCorp's cost of providing electricity to its retail customers.

PacifiCorp Retail Electric Tariff Structure Risk

Traditionally, most electric utilities including PacifiCorp have recovered relatively large portions of their fixed costs of doing business via energy-related charges that are a function of the amount of electricity actually consumed by its customers. In general, energy-related charges (and sometimes credits) are broadly considered to be all the items on a customer's power bill that are accessed on a cents per kWh basis. In the past, this business model worked well for the utilities since most customers, especially residential and small farm customers, had no viable alternatives available to purchase electricity from their local electric utility provider.

However, with the advent of lower cost and more efficient modular solar PV technology, many individual electricity customers now have a potentially cost-effective alternative that allows customers to displace at least a portion of the energy-related charges accessed by their local utility provider. The wide-spread adoption of small-scale solar PV installations in some areas of the Pacific Northwest and California has resulted in many utilities beginning to move away from recovering their fixed costs via energy-related charges. Instead, the electric utility industry is moving towards a new business model whereby the utility recovers a higher portion of its fixed costs via certain tariff charges that cannot be bypassed, or alternatively are difficult to bypass, by a customer if it self-generates. Examples of such charges are fixed monthly or annual "customer", "basic", or "connection" charges and so-called demand or capacity charges that are accessed based upon the customer's highest level of monthly electricity usage.

PacifiCorp's current Schedule 41 (in Oregon) and Schedule PA-20 (in California) retail irrigation tariffs contain a high level of energy-related charges during the irrigation season relative to a typical customer's overall monthly power bill. This is especially the case for customers that operate pumps or sprinklers on a continuous and high load factor basis.[77] Therefore, irrigation customers that are considering installing self-generating equipment should perform sensitivity analyses whereby they consider potential future changes in PacifiCorp's irrigation and drainage tariff structures that may contain a lower level of energy-related charges but a higher level of fixed or demand-related charges.

Changes in the Oregon and California Net Metering Programs

Similar to the net metering concept discussed in APM No. 2, the net metering programs currently in effect in Oregon and California allow individual end-use power customers to net their own self-generation against the full amount of the PacifiCorp's energy-related charges that would normally appear on their monthly power bills. In addition, Oregon customers who self-generate can effectively "bank" generation that is in excess of their usage in a given month and then use this banked generation to offset PacifiCorp's energy-related charges in a future month within the same 12-month accounting period. In California, self-generation that is in excess of a customer's usage is effectively cashed out at prevailing wholesale market power prices.

[77] For electrical loads (of any type) the load factor is a measure of average electricity usage divided by peak electricity usage across a defined period. For example, if a 50 HP pump with a peak electric usage of 37.3 kW used an average of 20 kW (=14,800 kWh total) during the month of July, the load factor for that month would be: 20/37.3 = 53.6%.

Oregon and California's net metering programs also allow for the limited development of shared generating facilities where multiple individual customers can receive a portion of the generation produced at a single, centralized facility in order to reduce a portion of their own energy-related charges from PacifiCorp. However, as described under APM No. 1, under the net metering programs currently in effect, shared Solar PV facilities are currently limited in size to 2,000 kW in Oregon and 1,000 kW in California.

PacifiCorp implements net metering with its customers pursuant to procedures that have been established by the Oregon and California Rate Commissions. However, these net metering procedures are subject to change in the future. Potential modifications to the existing programs could result in either increased or decreased benefits to electricity users. However, since any changes to the existing programs are subject to approval by either the OPUC or the CPUC, concerned stakeholders will have an opportunity to express their views as part of one or more public review processes. For irrigation customers in the Upper Klamath Basin who have either already installed net-metered self-generation, or who are considering doing so at some point in the future, it is imperative that their voices be heard in front of the Rate Commissions, on either an individual or group basis.

Changes in Federal or State Tax Incentives

The rapid expansion of renewable resource installations that have occurred across the last decade throughout the Pacific Northwest and California has been aided significantly by tax incentive programs enacted by the Federal government, and in some cases by the states as well. In particular, the availability of Federal Production Tax Credit (PTC) and Federal Investment Tax Credits (ITC), when combined with recent advances in wind power and solar power generating technology, has created a landscape whereby these renewable resources can now be economically competitive on a head-to-head basis with conventional generating technologies such as natural gas-fired combustion turbine plants.[78] Also, advances made by equipment manufacturers and energy investors in developing large-scale renewable resource facilities, especially solar PV technology-based, have undoubtedly "trickled down" to smaller-sized applications as well in the form of reduced equipment costs and increased conversions efficiencies for individual-customer sized installations.

Under current tax law, effective Jan 1, 2020 owners of new solar PV facilities of any size, including individual homeowner facilities, are eligible to receive the ITC, with the tax credit being 26% of the installation cost of the system/facility.[79] However, in 2021 the ITC will drop to 22% and in 2022 it will drop again to 10%. The ITC will sunset altogether in 2023 for small-scale solar PV facilities unless Congress takes further action. Therefore, for the purposes of implementing APM No. 1 (at any size scale), speed is of the essence for Basin water users/power users to receive the currently established level of tax-related benefits. It should be noted that while Congress has been willing in the past to extend the PTC and ITC tax incentive programs, there is no guarantee that Congress will continue to do so in the future.

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[78] The PTC was primarily designed to be applied to the development of new wind plants while the ITC can be applied to the development of either new wind or solar plants. A key different between the two tax credits is that the PTC is received across a 10-year period while the ITC is received in the form of a one-time, up-front benefit.

[79] Prior to January 1, 2020, the ITC was set at 30% of the cost of the system/facility.

Changes in Federal Import Tariffs and Policies

This risk category applies to those APMs (primarily Nos. 1, 3, 6 and 7) that might utilize equipment and parts that are manufactured outside of the United States. In particular, a large volume of the solar PV panels that have been installed in recent years in the US were manufactured in China. The import of these relatively low-cost panels helped to expand solar PV installations in many parts of the country at the residential and small-scale commercial level. This momentum is carrying over to the soon-to-be developed 150 MW – 200 MW grid-scale facilities. In addition, there are multiple companies that manufacture hydroelectric generating equipment at locations outside of the United States but that export this equipment for installation at (mainly) existing facilities located inside the US. Therefore, the results of cost/benefit analyses for some of the APMs – both on an absolute basis and on a relative basis as compared against other available APMs - could be impacted (in either a positive or negative fashion) by changing US trade and tariff policies.

Therefore, as Reclamation, irrigation districts and individual water users move ahead into the APM implementation stage, it is important for these entities to closely monitor the types of events and policies that might have an impact on the cost or availability of the specific equipment required to put desired APM(s) in place.

Changes in Long-term Interest Rates

The electric utility and power plant development industries are especially sensitive to changes in long-term interest rates. This is due to the fact that many of the capital improvements or investments in new infrastructure that these companies make: 1) involve large, upfront capital investments, and 2) the benefits received from these investments usually accrue across long periods of time. Since these types of projects are usually financed using various forms of long-term debt (such as issuing bonds), relatively small increases in long-term interest rates can have a significant impact on the economic viability of the proposed project. In addition, increases or decreases in long-term interest rates can tip the decision point between various generating technologies that have different useful lifespans.[80]

Fortunately, except for large-scale solar PV facilities under APMs Nos. 1, 3 and possibly 7 and the development of small hydro plants under APM No. 6, most of the APMs have limited long-term interest rate risk. However, it should be noted that PacifiCorp also has long-term interest rate risk as well and that, ultimately, its electricity customers (including irrigation/drainage customers in the Upper Klamath Basin) bear a portion of that risk via potentially higher PacifiCorp electric tariff rates in the future.

Changes in Regional, State, or Local Land-use/Water-use Policies

The implementation of some of the APMs, most notably No. 1 (Solar PV Development), No. 3 (Out-of-Basin Investment), No. 6 (Small Hydro Development) and possibly No. 7 (Federal Power Supply) could be subject to various regional, state, or local land-use or water-use policies that might restrict, or in some cases even prevent, water users in the Basin from implementing some of the desired alternatives under these APMs. For example, the siting of larger scale solar PV arrays in an area that has a significant amount of land area dedicated to agricultural production (like the Upper Klamath Basin) may be restricted by various land-use policies. Likewise, the development of small-

[80] For example, new solar PV facilities are generally considered to have a 25-year useful life while new small hydroelectric plants typically have a 50-year life.

scale hydroelectric plants within the Klamath Project would likely be subject to numerous water-use policies as well. Finally, the potential construction of new distribution or transmission lines that might be needed to interconnect new sources of renewable generation within the Basin to the bulk power grid would also need to be developed pursuant to established land-use and environmental policies.

Therefore, as Reclamation, irrigation districts, and individual water users move forward to consider implementation of APMs that may be subject to environmental, land-use or water-use policies, it is important that these entities proactively engage with the appropriate planning bodies in order to exchange information and establish up-front points of communication so that acceptable solutions to implementing the affected APMs can be mutually developed that balance the needs and concerns of Basin stakeholders.

Chapter 19 Potential Resources for Implementing the APMs

Overview

During the process of identifying and evaluating the set of nine APMs and potential energy efficiency upgrades, the APM Analysis Team recognized that irrigation customers may require assistance in further analyzing the power savings potential for their particular situation and, perhaps more importantly, developing a reasoned approach to implement the cost-savings measures in a cost-effective and timely fashion.

The APM Analysis Team is aware of a variety of organizations that can provide general knowledge, technical expertise, and in some cases funding, to assist irrigators in implementing one or more of the identified APMs, and water or energy efficiency upgrades. These organizations include federal and state governmental agencies and non-profits in both Oregon and California. As one example, the US Department of Agriculture's Rural Energy for America's funding possibilities can include total grants, matching grants, loan guarantees, or combination loan guarantees with grants. Grants range from $1,500 to $250,000 for efficiency upgrades or $2,500 to $500,000 for renewable energy systems.

Appendix E summarizes the types of organizations, their focus areas served (renewable energy, water or energy efficiency), equipment and practices funded, eligibility, applicable state(s), incentives (grants, loans, rebates), and availability (open vs pending or suspended).

Chapter 20 Summary Results of the Power Cost Benchmark Analysis

Overview

Along with the development of this APM Report, Reclamation has also been developing a separate Power Cost Benchmark (PCB) Report as directed in the AWIA. The primary purpose of the PCB Report is to objectively quantify the average per-unit power costs paid by agricultural water users for irrigation and drainage in other Reclamation irrigation projects that are located in the Pacific Northwest region and that are similarly situated to the Klamath Project.

Power Costs for Irrigation/Drainage in the Similar Projects

As is discussed in Chapter 8 of the PCB Report, five Reclamation Projects were selected to be the Similar Projects for the computation of the PCB. These five Projects, their general locations, and the calendar Year 2017-2018 average per-unit cost of power for irrigation and drainage in each Project is summarized in Table 20-1 below.

Table 20-1. Per-Unit Irrigation/Drainage Power Costs in the Five Similar Projects 2017-2018

Project	Location	2017/18 Average Per-unit Power Cost (¢/kWh)
Boise	South-western Idaho	7.046
Columbia Basin	East-central Washington	3.289
Minidoka	East/South-central Idaho	6.137
Owyhee	South-western Idaho/Eastern Oregon	5.643
Yakima	South-central Washington	6.699
Total		5.550

It should be noted that the average per-unit power costs shown in Table 20-1 incorporate both power supplies provided by multiple publicly-owned and investor-owned local electric utility companies and Federal Project-Use Power that is available to Reclamation and a limited number of irrigation districts located in the Similar Projects. Additional details regarding the derivation of the per-unit cost of power for irrigation/drainage in the five Similar Projects is included in Chapter 11 of the PCB Report.

Power Costs for Irrigation/Drainage in the Upper Klamath Basin

In contrast to the figures shown above in Table 20-1, the 2017 – 2018 average per-unit cost of power for irrigation/drainage for agricultural customers located in the Upper Klamath Basin - which includes Reclamation, multiple irrigation districts, and On-project and Off-project individual water users – is summarized in Table 20-2:

Table 20-2. Per-Unit Irrigation/Drainage Power Costs in the Upper Klamath Basin 2017-2018

Year	Oregon On-Project Average Per-Unit Power Cost (¢/kWh)	Oregon Off-Project Average Per-Unit Power Cost (¢/kWh)	California On-Project Average Per-Unit Power Cost (¢/kWh)	Combined Klamath Basin Average Per-Unit Power Cost (¢/kWh)
2017	11.076	11.043	15.031	11.801
2018	11.046	11.029	15.443	11.860
Weighted Average	11.061	11.036	15.237	11.830

Additional details regarding the derivation of the 2017 – 2018 per-unit cost of power for irrigation/drainage customers located in the Upper Klamath Basin is included in Chapter 10 of the PCB Report.

Comparison of Power costs for Irrigation/Drainage

A comparison of the figures contained in Tables 20-1 and 20-2 indicates that during the period 2017 – 2018, water users in the Upper Klamath Basin paid between 98.8% and 174.5% (with an average of 113.2%) more for electricity on a per-unit basis (depending upon their specific location within the Basin) than comparable irrigation/drainage customers located in the five Similar Projects. These results clearly indicate a need for Reclamation, Klamath Project irrigation districts, and individual water users in the Basin to aggressively move forward in a collaborative fashion to implement the identified high priority APMs to reduce power costs in the Basin down to the level of the PCB, consistent with the directives contained in the AWIA.

Chapter 21 Recommendations/Next Steps

Overview

The Power Cost Benchmark Analysis that accompanies this APM Report concluded that the average per-unit cost of power for irrigation and drainage use in the Upper Klamath Basin during calendar Years 2017 – 2018 was approximately 113.2% higher than the costs paid by agricultural water users located in five Reclamation Projects in the Pacific Northwest region that were identified as being similarly situated to the Klamath Project.[81] The Affordable Power Measures that have been evaluated and discussed in this Report, and especially those Measures identified as High Priority Measures in Table 17-2, are designed to assist water users including Reclamation, irrigation districts, and individual covered water users, in reducing their respective power costs using a multi-prong approach.

In developing the final list of High Priority APM's, an emphasis was placed on those Measures that could be implemented in a relatively short period of time to present water users with viable near-term power savings options that they could consider enacting, either on an individual customer basis or, in some cases, as part of a group. In addition, Measures implemented by Reclamation and irrigation districts will provide benefits to multiple individual water users.

Next Steps/Action Items

Consistent with the directives contained in the AWIA and the results of the companion PCB Report that indicates the average per-unit cost of electricity for agricultural water users in the Upper Klamath Basin during 2017 – 2018 was 113.2% higher than the per-unit costs for water users located in five similar Pacific Northwest irrigation Projects,[82] Reclamation recommends that the following actions be undertaken:

Action Item No. 1

Reclamation should immediately move forward to conduct next-level, full feasibility analyses for all of the high priority APMs identified in Table 17-2 of this Report, with the results of these analyses to be shared with irrigation districts and water users located in the Upper Klamath Basin as part of Action Item No. 3.

Action Item No. 2

Reclamation, irrigation districts, and water-user groups should immediately move to jointly sponsor the development of one or more analytical tools that can be used by individual water users in the

[81] *See* PCB Report, Chapter 13, Table 13-1. The cited figure is based upon the weighted average per-unit cost of power for irrigation/drainage customers located in both the Oregon and California portions of the Basin.
[82] The five Reclamation irrigation projects that were considered to be similarly situated to the Klamath Project (a/k/a the "Similar Projects") are listed in Table 20-1.

Basin to perform customized cost/benefits analyses for potential installation of self-generation systems. These tools would be open-sourced, for example utilizing Microsoft Excel, and would be designed to incorporate the: 1) unique aspects of highly seasonal irrigation/drainage loads, and 2) the specific details of the Oregon and California net metering programs. The APM Analysis Team believes that such tools could be developed relatively quickly and in a cost-efficient manner using existing models already developed by the Team as a starting point.

Action Item No. 3

Reclamation, in conjunction with existing or new water user groups in the Upper Klamath Basin should immediately form a committee (or alternatively utilize an existing committee or organization) that is specifically tasked with developing detailed plans to implement the identified high priority APMs. It is envisioned that this committee/organization would: 1) act as a "one-stop" source of resources and information in the Upper Klamath Basin for Reclamation, irrigation districts, and individual covered users, 2) would advise and assist individual water users/power users in moving forward to implement their own "best fit" suite of APMs, and 3) would act as a liaison with state and local land-use and water-use planning bodies regarding how the implementation of certain APMs could be achieved under established planning policies.

This central committee/organization would also be a primary contact point with other entities that can provide assistance to water users in implementing the APMs such as equipment providers (including solar PV installers), potential sources of funding (such as the Energy Trust of Oregon), and entities that can assist water-users in performing customized APM cost-benefit analyses. In addition, this committee/organization would provide a forum for Reclamation to share the results, and receive feedback on, the APM feasibility analyses to be conducted under Action Item No. 1.

Action Item No. 4

Reclamation, in conjunction with existing and new water user groups in the Upper Klamath Basin, should immediately form a committee whose primary focus is to be an advocate for agricultural power customers in the Basin at the Oregon and California Rate Commissions. In particular, such a committee would be actively involved in PacifiCorp General Rate Cases and power cost adjustments cases, along with providing input in various state-level decision making processes involving net metering policies, PacifiCorp's Long-Term Integrated Resource Plans, greenhouse gas reduction policies, proposal to re-structure PacifiCorp's retail electric sales tariffs, and other related issues that could potentially impact (either positively or negatively) the overall cost of power for irrigation/drainage customers in the Basin.

Abbreviations and Acronyms

$/MWh	Dollars Per Megawatt-Hour
¢/kWh	Cents Per Kilowatt-Hour
APM	Affordable Power Measures
AWIA	America's Water Infrastructure Act of 2018 (Pub L. 115-270)
BPA	Bonneville Power Administration
CAPP	Comprehensive Affordable Power Plan
CBP	Columbia Basin Project
COPCO	California Oregon Power Company
Corps	U.S. Army Corps of Engineers
COSA	Cost of Services Analysis
Draft PCT Report	Draft Klamath Power Cost Target Study Report
EIA	U.S. Energy Information Administration
EQIP	Environmental Quality Incentive Program
FERC	Federal Energy Regulatory Commission
FCRPS	Federal Columbia River Power System
GAO	Government Accountability Office
GRC	General Rate Case
IOUs	Investor-owned Utilities
IRP's	Integrated Resource Plans
KBRA	Klamath Basin restoration Agreement
kW	Kilowatt
kWh	Kilowatt-Hour
KWUA	Klamath Water Users Association
M	Million
Measures	Potential Power Cost Savings Measures
MWh	Megawatt-Hour
NASS	U.S. Department of Agriculture's National Agricultural Statistical Service
NRCS	Natural Resources Conservation Service
O&M	Operations and Maintenance
PCB	Power Cost Benchmark
PF	Priority Firm
PMA	Power Marketing Administration
PN	Pacific Northwest Generating Cooperative
PNW	Pacific Northwest
POUs	Publicly Owned Utilities
R&T Works	Reserved and Transferred Works
Reclamation	Bureau of Reclamation
ResEx	Residential Exchange Program
USBR	United States Bureau of Reclamation
USDA	United States Department of Agriculture
U.S. EIA	United States Energy Information Administration
WAPA	Western Area Power Administration

Appendices