RECLAMATION

Managing Water in the West

Klamath Comprehensive Agricultural Power Plan

Initial Alternatives Information Report

U.S. Department of the Interior
Bureau of Reclamation
Klamath Basin

February 2016

Mission Statements

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to Indian Tribes and our commitments to island communities.

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.

Klamath Comprehensive Agricultural Power Plan

Initial Alternatives Information Report

Prepared by

United States Department of the Interior
Bureau of Reclamation
Mid-Pacific Region
Klamath Basin Area Office

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Executive Summary

Introduction

The Bureau of Reclamation (Reclamation), on behalf of the Secretary of the Interior (Secretary), initiated a process to develop the Klamath Comprehensive Agricultural Power Plan (CAPP) to identify and evaluate alternatives with the potential to reduce power costs to approximately 1,900 power meters on Reclamation's Klamath Project in California and Oregon (On-Project users) and 600 power meters in Oregon not associated with the Klamath Project (Off-Project users). Together these meters serve more than 1,000 individual or corporate farms (See Figure ES-1).

The Reclamation Klamath Project was authorized by the Secretary in 1905. The Klamath Project is located in south central Oregon and northern California and provides water to approximately 210,000 acres of cropland in the Klamath Basin. It covers lands in Klamath County, Oregon, and Siskiyou and Modoc counties in northern California, as shown in Figure ES-1. The Off-Project area includes irrigated lands in Oregon on the watersheds of the Lost, Sprague, Williamson, and Wood rivers.

At the time of the Klamath Project's development, Reclamation recognized that in order to irrigate the land it was necessary to access inexpensive power for both drainage and pumping. 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, it was stymied by inadequate funding. In 1917, Reclamation entered into a 50-year agreement with the California-Oregon Power Company (COPCO), now PacifiCorp, for discounted power rates to the Klamath Project irrigators. In exchange for discounted power rates, Reclamation allowed COPCO to build Link River Dam on Upper Klamath Lake to provide better water regulation for COPCO's planned hydropower development on the Klamath River. The contract protected irrigation rights and provided the Klamath Project water users with locked-in 1917 power rates. The contract was amended in 1956 for an additional 50-year period including Off-Project agricultural power, and was incorporated as a provision of PacifiCorp's Klamath Hydroelectric Project Federal Energy Regulatory Committee (FERC) operating license.

At the expiration of the PacifiCorp's FERC license in 2006, the Klamath Basin irrigation community appealed to the Oregon and California Public Utility Commissions (PUCs) to preserve the reduced power rate agreements provided in the 1956 FERC license. Despite the appeals, the PUCs ultimately did not compel PacifiCorp to include reduced power provisions in the new license and allowed

PacifiCorp to phase in full tariff rates over a period of several years. PacifiCorp's FERC license expiration and the PUCs' ruling ended nearly 90 years of reduced or at-cost power rates for the Klamath On- and Off-Project irrigators.

Figure ES-1. Klamath Basin Area Subject to New PacifiCorp Tariffs

Purpose and Scope

The need for the CAPP resulted from the 2006 expiration of PacifiCorp's FERC license and a power contract serving Klamath Basin On- and Off-Project irrigators. This was followed in 2010 by the finalization of the Klamath Basin Restoration Agreement (KBRA) which sought to solve years of conflict in the Klamath Basin over water, power, and the environment. In the Power for Water Management Program (PWMP), the KBRA outlines provisions to provide affordable power to agricultural water users affected by the transition to

PacifiCorp tariff power rates. Reclamation, on behalf of the Secretary, is using the CAPP to identify and evaluate potential alternatives to reduce Basin irrigator power costs. The CAPP Initial Alternatives Information Report (IAIR) is the first major step in the study process to identify methods to reduce power costs to Basin irrigators.

The PWMP outlines the measures a new power management entity would take to implement a Financial and Engineering Plan for an affordable power program for the Upper Klamath Basin. Reclamation's intent is to have the CAPP function as a candidate Financial and Engineering Plan in the event Congress authorizes the KBRA or an alternative agreement. If Congress fails to provide authorizing legislation, Reclamation would rely on the Klamath Basin Water Supply Enhancement Act of 2000 (P.L. 106-498) (Enhancement Act) to implement the CAPP. The CAPP IAIR identifies and screens a comprehensive list of options to meet the CAPP objectives. The screening included preliminary technical, economic, and regulatory and policy viability. Viable options were formulated as alternatives with the ability to reduce agricultural power costs in On-Project and Off-Projects areas of the Basin. This report presents the result of the initial alternatives development and screening and identifies the alternatives that could be carried forward for additional analysis under either the Enhancement Act or KBRA authorizing legislation.

Study Authority

The authority to undertake the CAPP study is the Klamath Basin Water Supply Enhancement Act of 2000 (P.L. 106-498) (Enhancement Act). The Enhancement Act directs the Secretary of the Interior to engage in feasibility studies of, among other things, innovative water management measures to reduce conflicts over water in the Klamath Basin. In addition, although not a party to the KBRA, the U.S. Department of the Interior has expressed its intent to the signatory parties of the KBRA to take actions to advance the purposes of the KBRA that are consistent with the agency's existing legal authorities and the appropriations available for such purposes. Affordable power is integral to effective water management in the Klamath Basin, and must therefore be a part of any solution to Klamath Basin water issues as envisioned by the Enhancement Act.

Supporting Studies

In developing the IAIR, Reclamation undertook three studies that helped assess the viability of the CAPP approach and underlying questions of power use and regulation.

Initial Scoping Report – Undertaken to verify the validity of the proposed CAPP process as a means of reducing power costs or rates to Basin irrigators. The report documented case studies where irrigation districts in other locations throughout the western United States have implemented efficiency improvement or new power development projects to reduce power costs.

Regulatory Framework Report – Developed to identify the electrical generation, transmission, and distribution requirements and restrictions under which PacifiCorp operates to provide Klamath Basin power in Oregon and California. This report also identified the potential new programs that PacifiCorp or a utility district could undertake to reduce Basin irrigation power costs.

Basin Pumping Efficiency – Undertaken to evaluate the efficiency and energy consumption of the large pumping equipment in the Klamath Basin's irrigation systems, referred to as Reserved and Transferred Works, and the approximately 2,500 private irrigation pumps.

These studies are available at Reclamation's website, http://www.usbr.gov/mp/kbao/special_projects/power.html.

Stakeholder Participation

An important element of the IAIR's development was the stakeholder engagement program undertaken at major decision points and milestones during the alternatives development process. Basin stakeholders were engaged in the development and screening of options and alternatives. The stakeholder engagement program included four different stakeholder groups that represented different levels of interest and responsibility for the CAPP development. These groups included the Steering Committee, Technical Workgroup (TWG), Stakeholder Focus Group, and Klamath Tribes.

These groups provided feedback to Reclamation on strategies to develop power cost reduction options and in the development and review of CAPP work products. The majority of the input occurred at the TWG level with representation from both On- and Off-Project irrigators, the states of Oregon and California, and PacifiCorp.

Regulatory Framework

The California Public Utilities Commission (CPUC), and the Oregon Public Utilities Commission (OPUC) regulate power development, transmission, and distribution in the Klamath Basin. PacifiCorp is the owner and operator of the power distribution network in the Klamath Basin. As an investor-owned utility (IOU), PacifiCorp's California operations are regulated by CPUC and its Oregon operations are regulated by OPUC. PacifiCorp is also subject to other state and Federal agencies, including FERC. As such, PacifiCorp or a newly formed utility district must follow the regulations of each respective PUC when developing options to reduce power costs for Basin irrigators. A brief description of the regulatory entities follows.

CPUC and OPUC – The PUCs regulate consumer rates and services for IOUs, and are charged with ensuring the IOUs provide safe, reliable utility service at reasonable rates.

FERC – FERC is responsible for the interstate transmission of power and large power development. FERC requires all public utilities that operate interstate electrical transmission provide open access transmission tariffs for non-discriminatory transmission service to all transmission customers. FERC is also responsible for the Public Utility Regulatory Policy Act (PURPA) which creates a market for power from non-utility power producers referred to as "Qualifying Facilities." PURPA requires utilities such as PacifiCorp to buy power from independent Qualifying Facilities at their avoided cost rate, the rate it would cost the utility to generate the power.

PacifiCorp Operations

PacifiCorp owns the power distribution system in the Klamath Basin serving the basin pumping equipment. Any new power developed in the Basin would utilize PacifiCorp's distribution system and would be subject to the OPUC's and the CPUC's rules and regulation of their use. PacifiCorp's operating requirements and programs under the OPUC and CPUC vary substantially between the two states. A summary of PacifiCorp's operations in Oregon and California is provided below.

Oregon

In Oregon, PacifiCorp's primary OPUC-approved rate schedule is Schedule 41. Schedule 41 has an effective summer rate of 9.674 cents per kilowatt-hour (¢/kWh) for all services. Schedule 741 is PacifiCorp's Direct Access competitive rate schedule, which reduces Schedule 41 by 3.181 ¢/kWh because energy is supplied by an electricity service supplier (ESS). The two schedules include an annual basic charge of $1,210 for loads exceeding 300 kilowatts (kW) (approximately a 400-horsepower pump) and an annual load charge based on the maximum load (in kW) used in a given month.

PacifiCorp also provides rate schedules for off-peak power and net metering programs. The off-peak programs, Schedules 210 and 215, provide a credit for energy used during off-peak hours and an additional charge for energy used during on-peak hours. PacifiCorp's net metering program, Schedule 135, offsets energy costs for customers who generate up to 2,000 kW of renewable energy on-site, but does not compensate a generator for net excess annual energy production.

PacifiCorp provides Schedules 37 and 38 for the pricing of new power generation from Qualifying Facilities, paying the generator its avoided cost rate.

California

PacifiCorp offers California irrigators one rate schedule (Schedule PA-20) with a combined effective rate of 12.933 ¢/kWh. Schedule PA-20 includes an annual load charge of $149.31 plus a $15.63/kW load charge for loads exceeding 50 kW. For a typical 100 horsepower pump, the load charge can exceed $1,200 annually.

PacifiCorp offers a net metering program, Schedule NEM-35, capped at 1,000 kW per facility, under which customers with on-site renewable generation systems are compensated for annual net excess electricity.

In February 2015, PacifiCorp filed a request with the CPUC to establish a time-of use-pilot program similar to Oregon Schedule 215 which, if approved, would provide participating irrigation customers on Schedule PA-20 with a credit for energy used during off-peak hours and an additional fee for energy used during on-peak hours. If approved, the pilot would be available for the 2016 irrigation season to a very limited number of participants.

PacifiCorp does not maintain any programs for new power development in California that is not net-metered. New power development would fall under the general requirements of PURPA as a Qualifying Facility.

Table ES-1 presents the current electrical service schedules and energy charge rates offered by PacifiCorp in Oregon and California.

Table ES-1. Current PacifiCorp Energy Charge Rates

	Schedule	Load Limit	Total Rate (¢/kWh)	Annual Load Size Charge	Annual Basic Charge
OR	41	<1,000 kW	9.674	Loads ≤ 50 kW: $15/kW 3-Phase loads 50-300 kW: $10 /kW 3-Phase loads > 300 kW: $6/kW	≤50 kW: No Charge 51-300 kW: $310 >300 kW: $1,210
OR	210	<30 kW	On-Peak Summer: 8.004 On-Peak Winter: 3.737 Off-Peak: -1.231	See Schedule 41	See Schedule 41
OR	215 Pilot program	<1,000 kW	On-Peak: 22.313 Off-Peak: -3.161	See Schedule 41	See Schedule 41
CA	PA-20	<500 kW	12.933	All Loads: $15.63/kW plus Loads <50kW: $72.28 3-Phase loads >50 kW: $149.31	≤50 kW: $72.28 >50 kW: $149.31

Notes:
Winter is defined as November 1 through March 31, and summer as April 1 through October 31.
Annual load size charges are based on the peak load recorded.
300 kW is equivalent to a 400 horse power pump. 50kW is equivalent to a 66 horsepower pump.
Schedule 210 and 215 rates are added or subtracted from the Schedule 41 rates.

Energy Cost Reduction Regulatory Constraints

Numerous opportunities exist to reduce energy costs; however, many opportunities are constrained by PacifiCorp operations which are regulated by the OPUC and CPUC. A comprehensive Basin-wide energy cost reduction strategy is challenged by differing Oregon and California regulations. Promising programs in one state are not available or differ in the other state. A uniform set of policies that govern the Oregon and California portions of the Klamath Project would be ideal, but this is unlikely given the complexity and differences in rulemaking between the states. Table ES-2 summarizes the differences between Oregon and California programs.

Table ES-2. Comparison of Cost Reduction and Power Development Opportunities in Oregon and California

Opportunities	Oregon	California
Net metering allows customers to net meter excess power generation back onto the grid on an annual basis.	2,000 kW maximum with no reimbursement for annual overproduction. Restricted to one property owner or entity (irrigation district).	1,000 kW maximum with reimbursement for annual overproduction. Restricted to one property owner or entity.
Off-Peak rate programs offer customers lower rates during off-peak hours and impose additional charges during on-peak hours.	Pilot continuation and development as a future standard rate are uncertain.	Pilot program has not been approved by the CPUC. Proposed on-peak and off-peak rates are different from Oregon's.
Federal power offered through Bonneville Power Authority (BPA) (Oregon) or Western Area Power Authority (California)	Power provided through BPA provides potential cost savings on metered loads exceeding 17,000 kWh annually (approximately 50 percent of Oregon meters).	WAPA has no excess power to provide California loads.
Competitive electrical service supplier (ESS)	For the energy portion of the PacifiCorp bill (3.181 ¢/kWh), a metered load could procure competitive energy.	Unavailable.
Shared renewable programs allowing virtual metering and meter aggregation at renewable energy projects	No programs exist in Oregon that allow meter aggregation or virtual metering, although draft legislation has been developed.	Several programs exist in California, but PacifiCorp is not required to participate in these programs.
Pump efficiency improvements incentives	Cash efficiency incentives are available through the Energy Trust of Oregon.	Cash efficiency incentives are available through PacifiCorp.
PURPA Qualifying Facility for new power generation by a third party.	Sold to PacifiCorp at its avoided cost rate.	Sold to PacifiCorp at its avoided cost rate.

Development of Initial Alternatives

For CAPP options and alternatives, a baseline was developed that averages energy use from 2007 to 2013 and removes high energy use periods prior to 2007, when greater agricultural water diversions from the Klamath River were allowed. Table ES-3 identifies the baseline for future energy use for the three sectors of the Basin. This baseline was used to determine the energy cost reductions of the various options and alternatives.

Table ES-3. Basin Energy Use Baseline Derived from 2007 to 2013 Average Annual Energy Use

Sector	Energy Use (kWh)
Oregon On-Project	52,000.000
Oregon Off- Project	44,000,000
Oregon Total	96,000,000
California On-Project	22,000,000
Total	118,000,000

Source: PacifiCorp 2014

Power Cost Reduction Options Considered in the IAIR

Many options available in the Klamath Basin have the potential to lower the delivered energy costs for Basin irrigators; these include power development and generation and load reduction and demand management options. Reclamation developed an initial list of options in collaboration with CAPP stakeholders. The initial list of options assumed that some amount of funding would be available through the KBRA to support project development. Tables ES-4 and ES-5 provide the initial list of evaluated options.

Table ES-4. Initial Power Development Options

Option	Description
Natural Gas Development	Natural gas power generation facilities consistent with PURPA
Utility-Scale Solar	Utility-scale solar consistent with PURPA
Shared Utility-Scale Solar	Shared utility-scale solar development is defined as utility-scale solar that allows for community meter aggregation or virtual metering.
Biofuels	Biofuel power generation consistent with PURPA
Low-Head Hydropower	Low-head hydropower (hydro) development consistent with PURPA
Small-Scale, Net Metered Solar	Small-scale, net metered solar consistent with policies and regulations in Oregon and California. Small solar installations would be installed on select irrigation pumps in both states.
Fuel Cells	Natural gas-powered fuel cells would be used to generate electricity to drive an individual electric irrigation pump motor.
Geothermal	Geothermal power generation consistent with PURPA
Wind	Small and utility-scale wind generation. Wind generation was removed as an option because the Basin lacks a consistent and viable wind resource.

Table ES-5. Initial Demand Management, Investment, and Alternate Source Development Options

Option	Description
Federal Power	Through the KBRA PWMP, the Federal Power Delivery Workgroup evaluated delivering Federal power to the Basin irrigators. The Workgroup concluded that approximately 50 percent of the Oregon loads would experience a 10 percent rate reduction with power supplied by BPA. WAPA has no available power to serve California loads.
Time-of-Use	Time-of-use programs would be implemented consistent with current and proposed policies and regulations in Oregon and California. Economic benefits from time-of-use programs would accrue to irrigators opting into the program.
Irrigation Load Control	Irrigation load control would be implemented by PacifiCorp following policy changes that establish load control programs in Oregon and California. Economic benefits from irrigation load control would be distributed by PacifiCorp to participating irrigators in the form of annual compensation for unused power during designated shut-down periods in dollars per kilowatt-hour.
Efficiency and Equipment Improvements	Efficiency improvements provide an excellent opportunity to reduce energy costs through replacement or rehabilitation of inefficient equipment, reducing energy consumption.
On-Project Plan	The KBRA's On-Project Plan (OPP) balances water supply and demand for On-Project irrigators as a result of the KBRA's changes to water supply. The OPP options and alternatives potentially contain reduced pumping measures that reduce energy use.
Pump Conversion to Natural Gas	Pump conversion to natural gas could lower pumping energy costs. Natural gas could be supplied through fixed lines or by bottled compressed natural gas (CNG). Oregon's natural gas utility in the Klamath Basin area, Avista, could provide piped natural gas to some pump facilities. The California On-Project area does not have a natural gas utility. Most pumps would require service through CNG.
Out-of-Basin Investment in Renewable Energy Generation	Investment in renewable energy generation outside the Klamath Basin could be undertaken with KBRA funding. Economic benefits from investments in renewable energy generation could be distributed to all irrigators through an annual bill credit on an energy use pro-rata basis.

Options Screening

Screening Criteria and Performance Measures

Screening criteria and performance measures were developed to differentiate the characteristics of the CAPP initial options and later the formulated alternatives. The criteria define what an option or alternative achieves and the performance measures indicate how well an option achieves a specific criterion. As an example, Table ES-6 presents the metrics for how an option is consistent with all existing regulations and policies. Table ES-7 presents the full list of screening criteria used in the options screening process. Because it was anticipated that KBRA funding would be for CAPP alternatives, one screening criterion addresses consistency with the KBRA and two screening criteria relate to the access and distribution of available KBRA benefits to all irrigators.

Table ES-6. Example Screening Criterion- Consistency with Regulations and Policies

Measure	Description
Excellent	Consistent with all regulations and policies in both states
Good	Consistent with most regulations and policies in both states
Fair/Tolerable	Inconsistent with regulations and policies in one state
Poor	Inconsistent with regulations and policies in both states

Table ES-7. Options Screening Criteria

Criteria	Description
Consistency with the KBRA	The KBRA specifies that investments will be made in renewable resource generation or energy efficiency measures.
Consistency with Regulations and Policies	The states of Oregon and California have established their own regulations and policies for the generation, transmission, and distribution of power.
Access to Benefits	Three groups of irrigators could receive benefits under the KBRA: 1) Oregon On-Project, 2) Oregon Off-Project, and 3) California On-Project.
Equitable Distribution of Benefits	It is important that benefits provided by the KBRA are equitably distributed among all irrigators. This criterion is different from “Access to Benefits” in that it looks at the end benefit, not simply whether the program is accessible to all Basin irrigators.
Administrative Intensity	Each option will have different administrative requirements for the Management Entity to operate and maintain the option over its lifecycle and to manage and distribute any associated benefits.
Durability	The durability (life) of an option is a function of the technology employed, current regulations, and future policies.
Levelized Cost of Energy	The levelized cost of energy (LCOE) is a calculated cost of generating electricity in cents per kilowatt-hour (¢/kWh) at the point of connection to the electrical grid. The LCOE is a net present value calculation for the expected life of the project and is therefore a “levelized” cost for the project life.
Power Rates/ Costs	Each option will have the ability to reduce power costs for an individual irrigator through lowering rates or lowering the overall power cost by affecting another component of the energy use equation.
Environmental Impact	Each option will have some effect on the local environment.

Option Results Summary

Tables ES-8 and ES-9 summarize the evaluation of the demand management, investment, and alternate source development options and the power development options, respectively, against the CAPP performance measures. Generally, options at the top of the tables performed best while options towards the bottom performed worst. The most important criteria identified by stakeholders were an option’s ability to lower power costs or rates, followed by access to and distribution of benefits. Since the demand management, investment, and alternate source development options do not develop power, LCOE is not used as a screening criteria.

Table ES-8. Summary of Demand Management, Investment, and Alternative Source Development Option Screening Evaluation

Option	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Efficiency/equipment improvements	Excellent/Yes	Excellent/Yes	Good	Fair/Tolerable	Fair/Tolerable	Excellent/Yes	Good	Good	Excellent/Yes
Irrigation load control	Excellent/Yes	Poor/No	Good	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Good	Good	Excellent/Yes
Out-of-Basin renewable investment	?	?	Excellent/Yes	Excellent/Yes	Good	Good	Fair/Tolerable	Good	Excellent/Yes
Time-of-use	Excellent/Yes	Fair/Tolerable	Good	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Excellent/Yes
Pump conversion to natural gas	Poor/No	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Poor/No	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable
OPP options	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Good	Excellent/Yes	LN		NA

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No ?: Unknown LN: Low to neutral effect on Basin power costs NA: Not evaluated

Table ES-9. Summary of Power Development Option Screening Evaluation

Option	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Utility-scale solar	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Good	Excellent/Yes	Excellent/Yes 1.89	Fair/Tolerable 7	Fair/Tolerable 9	Good
Small-scale solar (Net Metered)	Excellent/Yes	Good	Good	Fair/Tolerable	Excellent/Yes	Good	Excellent/Yes 1.98	Fair/Tolerable 16	Good 26	Excellent/Yes
Low-head hydro	Excellent/Yes	Excellent/Yes	Good	Fair/Tolerable	Fair/Tolerable	Excellent/Yes	Excellent/Yes 1.98	Fair/Tolerable 10	Fair/Tolerable 12	Fair/Tolerable
Progressive utility-scale solar	Excellent/Yes	Poor/No	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Good	Excellent/Yes 1.92	Fair/Tolerable 19	Good 33	Good
Fuel cells	Poor/No	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable	Good	Good	Fair/Tolerable 8.30	Good 33	?	Good
Geothermal - conventional	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Good 4.56	Poor/No 3	Poor/No 4	Good
Geothermal - enhanced	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Poor/No 12.61	Poor/No -9	Poor/No -10	Good
Biofuels	Excellent/Yes	Excellent/Yes	Good	Good	Good	Fair/Tolerable	Good 4.56	Poor/No -24	Poor/No -29	Fair/Tolerable
Natural gas development > 5 MW	Poor/No	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Fair/Tolerable 7.90	Poor/No -16	Poor/No -19	Poor/No
Natural gas development < 5 MW	Poor/No	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Poor/No 9.20	Poor/No -17	Poor/No -21	Poor/No

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No ?: Unknown

Alternatives Formulation and Initial Screening

The retained Klamath CAPP options were combined into 12 preliminary alternatives. Options were grouped together based on complementary benefits that could, for the group, result in increased performance against screening criteria. Major common assumptions used to develop alternatives included:

- KBRA funded initial investment of $40 million would be provided for qualifying alternatives.
- PURPA developed power would be sold to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.

- Alternatives developing revenue would reduce energy costs through a bill credit to all irrigators.

Alternative 1: Utility-Scale Solar

Alternative 1 would develop approximately 15.4 megawatts (MW) of solar photovoltaic (PV) electricity using single axis tracking technology at single or multiple distributed sites.

Alternative 2: Low-Head Hydropower

Alternative 2 would develop up to 4 MW of low-head hydroelectric power (hydro). The Klamath Project area has several potential locations for low-head hydro resources. A summary of the evaluated hydro sites is presented in Table ES-10. Hydro on Keno dam provided the best ratio of project cost to annual net revenue (cost-benefit ratio).

Table ES-10. Summary of Cost, Energy, and Revenue for Low-Head Hydro Options

Hydro Option Site	Project Cost ($ million)	Annual Energy Production (GWh)	Annual Net Revenue ($)	Ratio of Project Cost to Annual Net Revenue
Keno Dam	35.9	27.4	817,700	44
Westside Powerhouse	5.8	3.8	113,600	51
Eastside Powerhouse from A Canal	17.0	11.5	326,300	52
Eastside Powerhouse from Link River Dam	24.6	14.9	440,700	56
A Canal	10.5	4.9	137,800	76
G Canal	4.3	1.4	38,800	111

Alternative 3: Out-of-Basin Investment

Alternative 3 would invest $40 million in pure-play renewable energy assets through a yieldco. A yieldco is a dividend-yielding public company that bundles renewable energy and generates a predictable cash flow from long-term power contracts on the operating asset. As part of this alternatives development, it was determined to be consistent with the KBRA.

Alternative 4: Utility-Scale Solar and Out-of-Basin Investment

Alternative 4 would develop approximately 7.7 MW of solar PV electricity using single axis tracking technology at one or two distributed sites. The other half of the funding would be invested in renewable energy through a yieldco that produces an annual yield.

Alternative 5: Geothermal

Alternative 5 would develop approximately 7 MW of electricity using conventional geothermal technology at an unspecified location in the Basin.

Alternative 6: Shared Solar

Alternative 6 would develop approximately 12 MW of solar PV electricity using single axis tracking technology at multiple distributed sites. Shared solar allows for community meter aggregation or virtual metering. Solar power would be developed at 25 to 50 generating facilities, each serving 50 to 100 virtual meters. Current policies do not allow virtual metering or aggregation in Oregon and it is not required of PacifiCorp in California.

Alternative 7: Utility-Scale and Net Metered Solar

Alternative 7 combines utility-scale solar development with net metered solar, leveraging Oregon and California net metering incentives. This alternative would develop approximately 7 to 8 MW of solar PV using single axis tracking technology and would install approximately 1,000 small-scale solar PV systems.

Alternative 8: Net Metering

Alternative 8 would develop approximately 4 to 8 MW of electricity using a combination of small-scale solar PV systems and natural gas-powered fuel cells. To maximize the number of individual net metering opportunities, solar PV systems would be limited to a capacity of 5 kW and fuel cells to 8 kW. The power generated by these systems would be net metered, offsetting the cost of the electricity supplied by PacifiCorp.

Alternative 9: Demand Management

Alternative 9 adjusts irrigation operations to maximize access to PacifiCorp’s time-of-use and load control programs. A funding pool would be established to build infrastructure, including water storage in the irrigation system and equipment modifications to facilitate district-level and on-farm time-of-use and load control operation. Disruption to water deliveries at the district level could occur with large scale shifts to demand management.

Alternative 10: Revenue Stream and Efficiency

Alternative 10 would maximize district-level and on-farm pumping efficiencies. Pump and motor efficiency improvements would leverage PacifiCorp and Energy Trust of Oregon incentive programs. A funding pool would be established for pump and motor efficiency improvements. A revenue stream would be established through an out-of-Basin investment or PURPA Qualifying Facility.

Alternative 11: Natural Gas Development

Alternative 11 is a natural gas only alternative and would capitalize on cost savings generated by using natural gas motors over electrical motors. Net metered natural gas fuel cells in Oregon could provide economic advantages over a direct electrical connection.

Alternative 12: Regional Maximized Opportunity

Alternative 12 would maximize each region's ability to reduce power rates and/or costs by leveraging region-specific opportunities in the Oregon On-Project, Oregon Off-Project, and California On-Project areas. The region-specific opportunities are generally contained in Alternatives 1 through 11.

Initial Alternatives Screening Evaluation

The preliminary alternatives were assessed against the screening criteria and performance measures. The results of this evaluation are shown in Table ES-11.

The general performance of the initial alternatives are as follows:

- Alternatives 1, Utility Scale Solar; 3, Out-of-Basin Investment; 4, Utility Scale Solar and Out-of-Basin Investment; and 7, Utility Scale Solar and Net Metering perform well against all screening criteria.

- Alternative 5, Geothermal requires a large capital investment with an uncertain performance in a yet-to-be-identified geothermal field.

- Alternative 6, Shared Solar performs well against all screening criteria except the large uncertainty of changing regulatory policies in Oregon and California.

- Alternative 8, Net Metering has the greatest potential to lower energy rates behind the meter. This alternative is challenged by the inconsistencies associated with net metering fuel cells in California and Oregon.

- Alternative 9, Demand Management could disrupt agricultural water deliveries and none of the programs have final approval from state PUCs.

- Alternative 10, Revenue Stream and Efficiency would be challenged to equitably distribute benefits to all irrigators.

- Alternative 11, Natural Gas is challenged by Avista's small natural gas distribution system. Large-scale conversion of electrical irrigation equipment to natural gas pumps would also be costly.

Table ES-11. Summary of Preliminary Alternative Screening Analysis

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Alternative 1: Utility-Scale Solar	Excellent	Excellent	Excellent	Excellent	Good	Excellent	Fair/Tolerable	Fair/Tolerable
Alternative 2: Low-Head Hydro	Excellent	Good	Good	Good	Good	Good	Fair/Tolerable	Fair/Tolerable
Alternative 3: Out-of-Basin Investment	Excellent	Excellent	Excellent	Excellent	Good	Good	Good	Excellent
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	Excellent	Excellent	Excellent	Excellent	Good	Excellent	Good	Good
Alternative 5: Geothermal	Excellent	Excellent	Excellent	Excellent	Fair/Tolerable	Excellent	Poor	Good
Alternative 6: Shared Solar	Excellent	Poor	Excellent	Excellent	Fair/Tolerable	Good	Good	Good
Alternative 7: Utility-Scale and Net Metered Solar	Excellent	Excellent	Excellent	Excellent	Good	Excellent	Good	Good
Alternative 8: Net Metering	Fair/Tolerable	Fair/Tolerable	Good	Good	Fair/Tolerable	Excellent	Excellent	Excellent
Alternative 9: Demand Management	Excellent	Fair/Tolerable	Good	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable	Good	Good
Alternative 10: Revenue Stream and Efficiency	Excellent	Excellent	Good	Fair/Tolerable	Fair/Tolerable	Excellent	Good	Good
Alternative 11: Natural Gas	Poor	Fair/Tolerable	Fair/Tolerable	Poor	Fair/Tolerable	Good	Poor	Fair/Tolerable

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

Initial Alternatives Ranking

An alternatives ranking poll was distributed to the stakeholder TWG to assess their support for the initial CAPP alternatives and to establish a preliminary ranking of the alternatives. The TWG was supplied with a list of uncertainties for each alternative and the preliminary alternative screening analysis.

The poll used the "gradient of agreement" concept to gauge individual stances on each alternative, as shown in Figure ES-2. This scale provides a simple method for scoring alternatives. An alternative score was determined by factoring in the number of votes and grade (1 through 5) of votes for the alternative.

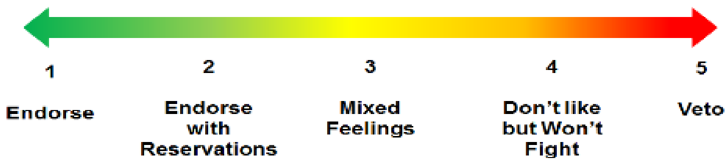

Figure ES-2. Gradient of Agreement for Alternatives Rating

Responses were collected from the irrigation community and outside policy reviewers. Table ES-12 provides the results, which are organized into three tiers (best to worst).

Table ES-12. Poll Results Based on TWG and Outside Policy Reviewer Respondents

Alternative	1. Endorse	2. Endorse with Reservations	3. Mixed Feelings	4. Don't like, but Won't Fight	5. Don't Like	Score
Tier 1						
Alternative 7: All Solar	5	2	1	1	0	16
Alternative 6: Shared Solar	4	3	2	0	0	16
Alternative 3: Out-of-Basin Investment	5	1	1	2	0	18
Alternative 10: Revenue Stream and Efficiency	5	1	1	2	0	18
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	2	4	2	1	0	20
Tier 2						
Alternative 8: Net Metering	1	4	4	0	0	21
Alternative 1: Utility-Scale Solar	1	4	3	0	1	23
Alternative 9: Demand Management	2	3	2	0	2	24
Alternative 2: Low-Head Hydro	1	2	4	1	1	26
Tier 3						
Alternative 12: Regional Maximized Opportunity	3	0	1	3	2	28
Alternative 11: Natural Gas	0	0	2	3	4	38
Alternative 5: Geothermal	0	0	1	4	4	39

Final IAIR Alternatives Ranking

Following initial alternatives development and screening, additional economic analysis was performed on the Tier 1 and 2 alternatives to understand the alternatives' ability to reduce power costs. A brief discussion of the results of the additional economic analysis as well as new information on biomass power development provided by the Klamath Tribes is provided below.

Revised Economic Analysis

Each CAPP alternative has the ability to lower power costs for individual Basin irrigators, either by lowering delivered energy rates received from the local utility or by lowering the overall power cost by affecting another component of the energy use equation. Further economic analysis was undertaken to provide an in-depth representation of project revenue and associated economic benefits.

Power Rate Reduction

Rate reduction percentages for CAPP alternatives were calculated separately for Oregon and California, where possible. Economic benefits were allocated to Oregon and California on an energy use basis (roughly 81 percent Oregon, 19 percent California). Alternatives resulting in the generation of revenue would distribute the revenue to Basin irrigators on a kilowatt-hour (kWh) pro-rata basis, and would be applied equally across all PacifiCorp Oregon Schedule 41 and California PA-20 users through a bill credit.

Alternatives Ranking

A revised alternatives ranking was conducted following the additional economic analysis as shown in Table ES-13. Where possible, an estimate is calculated for the average energy rate reduction an alternative would yield for irrigators in California and Oregon. The additional economic analysis resulted in the following:

- Five of the six options in Alternative 2, Low-Head Hydro, were moved down from Tier 2 into Tier 3 after analysis determined that the projects were not economically feasible. In the case of the Eastside and Westside powerhouses, PacifiCorp disclosed that competitive bidding would be employed to establish their fair market, providing no guarantee of their acquisition.
- Alternative 8, Net Metering, was moved up from Tier 2 into Tier 1.
- Alternative 10, Revenue Stream and Efficiency, was moved down from Tier 1 into Tier 2.
- Alternative 13, Biomass Power Development, was reintroduced and placed in Tier 2. Biomass was removed from the CAPP options formulation process during earlier screening due to its high LCOE relative to other power generation options. However, the Klamath Tribes are studying a number of potential feedstock programs that could provide

less expensive feedstock, potentially making biomass competitive with other power development options.

Tier 1 presents the best opportunities while Tier 2 represents opportunities that have promise but may contain implementation obstacles or provide a lower potential for reducing rates. Tier 3 alternatives represent alternatives that do not reduce rates or contain substantial uncertainties.

Table ES-13. Revised Alternatives Ranking

Alternative	Average Rate Reduction[1] Oregon	Average Rate Reduction[1] California
Tier 1		
Alternative 7: Utility-Scale and Net Metered Solar	9.7%	9.1%
Alternative 6: Shared Solar	23.1%	17.2%
Alternative 3: Out-of-Basin Investment	8.0%	6.0%
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	6.3%	4.7%
Alternative 8: Net Metering	19.4%	12.8%
Tier 2		
Alternative 1: Utility-Scale Solar	4.3%	3.2%
Alternative 10: Revenue Stream and Efficiency[2]	up to 15%	up to 15%
Alternative 9: Demand Management[2]	up to 51.7%	up to 47.1%
Alternative 2: Hydro at Keno Dam	5.6%	4.2%
Alternative 13: Biofuels and Biomass Power Development	NA	NA
Alternative 12: Regional Maximized Opportunity	NA	NA
Tier 3		
Alternative 2: Hydro at Eastside Powerhouse	3.0%	2.2%
Alternative 2: Hydro at Eastside Powerhouse with A Canal Water	2.2%	1.6%
Alternative 2: Hydro at A Canal	0.9%	0.7%
Alternative 2: Hydro at Westside Powerhouse	0.8%	0.6%
Alternative 2: Hydro at G Canal	0.3%	0.2%
Alternative 11: Natural Gas Development	NA	NA
Alternative 5: Geothermal	4.6%	3.4%

[1] The values shown here represent the average rate reduction percentage from 2015 to 2041, based on the standard pricing option provided in Schedule 37, where applicable.
[2] These values represent the potential savings for an individual Basin irrigator.
[NA] No additional analysis was performed.
Note: The full evaluation of each applicable CAPP alternative can be found in Appendix E, Klamath CAPP Alternatives Economic Analysis.

Next Steps

While Federal legislation for the KBRA or an alternative settlement agreement is one means of advancing the CAPP, another opportunity is through the Enhancement Act. By using the Enhancement Act, Reclamation would undertake a Federal feasibility study in conjunction with a local non-Federal Project Sponsor(s) to advance and ultimately implement the CAPP preferred alternative.

The next steps to advance the CAPP Feasibility Study are defined in Directive and Standards (D&S) CMP 09-02, and are presented below.

1. Identify the Project Sponsor(s). Reclamation would work with the Basin irrigation community to identify non-Federal organizations or agencies to act as the Project Sponsor(s) in the On- and Off-Project areas. The Project Sponsor(s) would help Reclamation define the CAPP's next steps, including the alternatives to be investigated in the feasibility study.

2. Prepare a Plan of Study. The Plan of Study defines the study elements of the feasibility study and clearly defines its objectives and scope. The Plan of Study also defines the role of the Project Sponsor(s) and cost sharing including any in-kind services. The alternatives defined in this IAIR would provide the foundation for the Plan of Study. There are two actions required of the Project Sponsor(s) to define the CAPP Feasibility Study scope:

- The Project Sponsor(s) would take a lead role in the development and advancement of new Federal legislation to serve the Off-Project area. Without this, Reclamation's authority is limited to the On-Project area.
- The Project Sponsor(s) would take a lead role in advancing changes to the OPUC and CPUC regulations and policies effecting opportunities to reduce irrigation power costs. These changes include the evolving time-of-use and shared renewable programs in both states, where new policies could provide cost relief as defined in several alternatives presented in this IAIR.

3. Prepare the CAPP Feasibility Study. Reclamation would conduct the CAPP feasibility study in coordination with the Project Sponsor(s) to define the best alternatives for achieving the CAPP objectives, including economic justification for the preferred alternative. To receive Federal funding and environmental clearance for project development, the feasibility study would be performed in conjunction with environmental compliance processes such as those falling under the National Environmental Policy Act, Endangered Species Act, and other laws and regulations. While the Enhancement Act allows for 100 percent non-reimbursable funding for the feasibility study (under the D&S, feasibility studies normally include some element of cost share), in the absence of Congressional action providing separate funding, project development would be fully reimbursable under the Reclamation Act.

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Abbreviations and Acronyms

¢/kWh	cents per kilowatt-hour
Avista	Avista Corporation
Basin	Klamath Basin
BPA	Bonneville Power Administration
CA	California
CAPP	Comprehensive Agricultural Power Plan
CCA	Community Choice Aggregation
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
cfs	cubic feet per second
CNG	compressed natural gas
CO_2	carbon dioxide
COPCO	California Oregon Power Company
CPUC	California Public Utilities Commission
CSIP	California Solar Incentive Program
D&S	Directive and Standard
DLAP	default load aggregation point
DOI	United States Department of the Interior
EGS	enhanced geothermal systems
EIM	energy imbalance market
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
Energy Trust	Energy Trust of Oregon
Enhancement Act	Klamath Basin Water Supply Enhancement Act of 2000
ESS	electricity service supplier
FAR	Final Alternatives Report
FERC	Federal Energy Regulatory Commission
GTD	generation, transmission, and distribution
GWh	gigawatt-hours
hydro	hydropower
IAIR	Initial Alternatives Information Report
ID	irrigation district
IOU	investor-owned utility

ISO	California Independent System Operator
KBPA	Klamath Basin Power Alliance
KBRA	Klamath Basin Restoration Agreement
KDD	Klamath Drainage District
KHSA	Klamath Hydroelectric Settlement Agreement
KID	Klamath Irrigation District
KSD	Klamath Straits Drain
kW	kilowatt
KWAPA	Klamath Water and Power Agency
kWh	kilowatt-hours
LCOE	levelized cost of energy
m/s	meters per second
MW	megawatt
MWh	megawatt-hours
NEPA	National Environmental Protection Act
NERC	North American Electric Reliability Corporation
NMFS	National Marine Fisheries Service
NREL	National Renewable Energy Laboratory
NWR	National Wildlife Refuge
O&M	operations and maintenance
OATT	open access transmission tariff
ODOE	Oregon Department of Energy
OPP	On-Project Plan
OPUC	Oregon Public Utility Commission
OR	Oregon
OWRD	Oregon Water Resources Department
PG&E	Pacific Gas and Electric Company
PPA	power purchase agreement
PUD	people’s utility district
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
PWMP	Power for Water Management Program
REIT	real estate investment trust
R&T Works	Reserved and Transferred Works
Reclamation	Bureau of Reclamation

RES-BCT	Local Government Renewable Energy Self-Generation Bill Credit Transfer Program
RPS	Renewables Portfolio Standard
Secretary	Secretary of the Interior
SFG	Stakeholder Focus Group
SMUD	Sacramento Municipal Utility District
TID	Tulelake Irrigation District
TWG	Technical Workgroup
U.S.	United States
USFWS	U.S. Fish and Wildlife Service
WAPA	Western Area Power Administration
WECC	Western Electric Coordinating Council
Workgroup	Federal Power Delivery Workgroup

Chapter 1 Introduction

The Bureau of Reclamation (Reclamation), on behalf of the Secretary of the Interior (Secretary), initiated a process to develop the Klamath Comprehensive Agricultural Power Plan (CAPP) to identify and evaluate alternatives with the potential to reduce power costs to approximately 1,900 power meters on Reclamation's Klamath Project in California and Oregon (On-Project users) and 600 power meters irrigators in Oregon not associated with the Klamath Project (Off-Project users). Together these meters serve more than 1,000 individual or corporate farms. The need for the CAPP resulted from two substantial events in the Klamath Basin:

- The 2006 expiration of PacifiCorp's Federal Energy Regulatory Committee (FERC) license and a power contract serving Basin irrigators ended nearly 90 years of reduced power rates for the Klamath Basin On-Project and Off-Project irrigators. Implementation of full-tariff power rates has resulted in an average pumping cost of $45 per acre per year, compared to the previous power contract rate of $2.25 per acre per year.

- In 2010 the Klamath Basin Restoration Agreement (KBRA) was finalized following several years of negotiations to mitigate water, power, and environmental conflicts within the Klamath Basin. The KBRA outlines provisions in the Power for Water Management Program (PWMP) section to provide affordable power to agricultural water users affected

CAPP Objectives

The CAPP was established to plan and implement an affordable power program for the Upper Klamath Basin, defined as the Klamath Project and upstream Off-Project area, in close alignment with the PWMP of the KBRA, and in collaboration with the KBRA PWMP management entity, the Klamath Basin Power Alliance (KBPA).

The objectives of the PWMP are to provide affordable electricity to:

- "Allow efficient use, distribution, and management of water within the Klamath Reclamation Project and the National Wildlife Refuges, and facilitate the return of water to the Klamath River as part of the implementation and administration of the On-Project Plan
- Implement the Water Use Retirement Program and Off-Project Water Settlement
- Realize objectives of the Fisheries Restoration Program
- Provide power cost security to assist in maintaining sustainable agricultural communities in the Upper Klamath Basin"

The PWMP "includes measures and commitments based on a delivered power cost target that will be at or below the average cost for similarly situated Reclamation irrigation and drainage projects in the surrounding area…." (KBRA 2010) by the transition to PacifiCorp tariff power rates. Reclamation, on behalf of the Secretary, is using the CAPP to identify and evaluate potential alternatives to reduce Basin irrigator power costs. The CAPP is intended to provide a general roadmap for the Basin irrigators to implement a program to achieve the lowest possible power costs.

1.1 Purpose and Scope of the CAPP

The CAPP Initial Alternatives Information Report (IAIR) is the first major step in the study process to identify methods to reduce power costs to Basin irrigators. In accordance with the PWMP, the Management Entity is responsible for the development of a Financial and Engineering Plan to implement an affordable power program for the Upper Klamath Basin. The Management Entity, identified as the Klamath Basin Power Alliance (KBPA), must submit the plan to the Secretary for approval and adopt the plan within 45 days of the Secretary's approval. Reclamation's intent is to have the CAPP Final Alternatives Report function as a candidate Financial and Engineering Plan for the KBPA in the event that the KBRA is authorized by Congress. The KBPA can exercise its discretion to adopt or modify the CAPP to serve as the Financial and Engineering Plan. If approved as the Financial and Engineering Plan by the KBPA, Reclamation would proceed with assessment of environmental impacts to allow for the expenditure of Federal funds for the PWMP[1].

In the event that Congress fails to provide legislation authorizing the KBRA, Reclamation would rely on the Klamath Basin Water Supply Enhancement Act of 2000 (P.L. 106-498) (Enhancement Act) to implement the CAPP. The process using the Enhancement Act to implement the CAPP is described in Section 1.2, Authority.

The CAPP studies three principal elements to identify the best renewable energy development and conservation and efficiency options, as called for in the PWMP, to serve as the candidate Financial and Engineering Plan:

- **IAIR –** The IAIR identifies and screens a comprehensive list of options to meet the CAPP objectives. The screening included preliminary technical, economic, and regulatory and policy viability. Viable options were then formulated as alternatives with the ability to reduce agricultural power costs in On-Project and Off-Projects areas of the Basin. This report presents the result of the initial alternatives

[1] The CAPP defines only the Federal government's role in achieving affordable power for the Klamath Basin and does not preclude private, independent action by stakeholders. Private funds can be expended at any time, with potential leverage from water and energy efficiency grants or under other state or Federal authority or funding, as appropriate.

development and screening and identifies the alternatives that will be carried forward for additional analysis in the next steps.

- **Final Alternatives Report (FAR)** **–** The FAR will further evaluate the technical, economic, regulatory, and policy viability of the best-performing CAPP IAIR alternatives supported by the CAPP stakeholders, as further defined below. The FAR will include preliminary design of selected alternatives and will be developed to meet the requirement of the Financial and Engineering Plan identified in the PWMP.

- **Assessment of Environmental Impacts –** Prior to implementation, the CAPP process will include a formal assessment of the potential environmental impacts of the FAR alternatives. This could include the development of an Environmental Impact Statement and Environmental Impact Report or a lesser study to satisfy the National Environmental Policy Act, California Environmental Quality Act (CEQA), and other applicable federal, state, and local laws. Reclamation will issue a decision document that identifies the preferred alternative for implementation.

The IAIR presents the initial proposed CAPP alternatives and the screening and development process used to identify and refine the alternatives. To ensure the CAPP meets the needs of both the Secretary and the KBPA, the options and alternatives were reviewed through a stakeholder engagement process that included the irrigation community, regulatory interests from Oregon and California, PacifiCorp, and the general public. This process is discussed further in Chapter 2, Stakeholder Program. Each chapter of this report references how the stakeholder process influenced alternatives development.

1.2 Authority

This section addresses Reclamation's authority to undertake the CAPP study. The primary authority to undertake the CAPP study is the Enhancement Act. In addition, although not a party to the KBRA, the U.S. Department of the Interior (DOI) has expressed its intent to the signatory parties to take actions consistent with the KBRA that are consistent with the agency's existing legal authorities and the appropriations available for such purposes.

The Enhancement Act directs the Secretary to engage in feasibility studies of, among other things, innovative water management measures to reduce conflicts over water in the Klamath Basin. Because effective agricultural water management relies on affordable power, feasibility studies directed towards development of affordable power are consistent with the purpose of the Enhancement Act.

In the event the KBRA is authorized by Congress and becomes Public Law, implementation of the CAPP would be authorized by this public law and any funds associated with the authorizing Public Law would be spent consistent with the IAIR, FAR, and environmental compliance process. In the event Congress fails to provide legislation authorizing the KBRA, Reclamation's actions are limited to feasibility studies as authorized by the Enhancement Act. Upon completion, such feasibility studies are to be forwarded to Congress for action.

Although the two processes are similar, a few modifications would occur if the CAPP is ultimately developed under the Enhancement Act. Primarily, the CAPP would be completed consistent with Reclamation's Directives and Standards CMP 09-02 which outlines the process and requirements for the development of water and related resources feasibility studies. For the CAPP to be developed as a feasibility study, the following modifications would be undertaken:

- **Develop an Appraisal Study** – An appraisal study is required for all feasibility studies. The appraisal study is an initial planning level investigation that determines the nature of the resource problem, identifies preliminary alternatives, and establishes Reclamation's interest in the project. Although a formal appraisal study has not been performed, the information contained within this CAPP IAIR meets the requirements of an appraisal study and defines Reclamation's interest in the CAPP.

- **Identify a Cost-share Partner –** Feasibility studies require the identification of a non-Federal cost-sharing partner unless directed otherwise by Congress. The regional director and the Commissioner can waive the cost-share requirements if justified by an overwhelming Federal interest in the study and requested by the cost-share partner. The cost-share partner, also referred to as the local sponsor, assists with developing the feasibility study to meet the project objectives.

- **Prepare a Plan of Study –** Prior to undertaking the feasibility study, Reclamation would develop a Plan of Study with the local sponsor. The Plan of Study describes the specific study tasks, responsible parties, approach, and schedule to complete all elements of the feasible study.

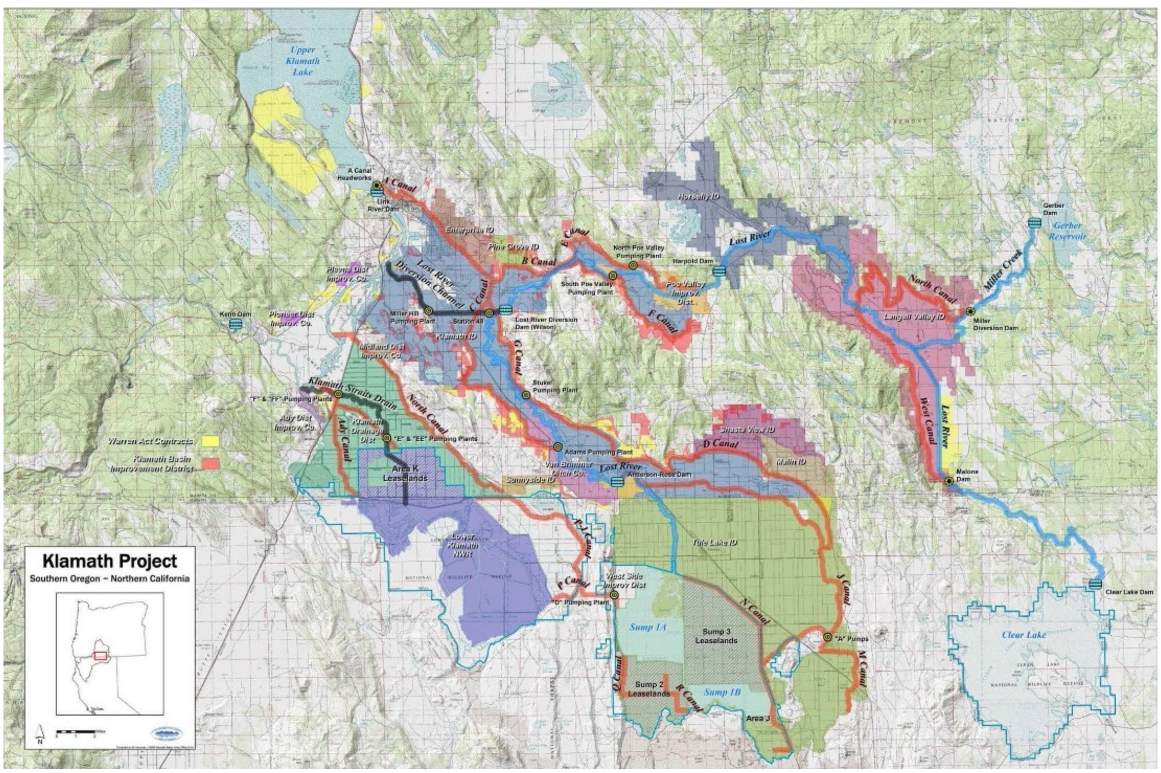
- **Prepare a Joint Feasibility Study and National Environmental Protection Act (NEPA) Compliance Document –** The feasibility study and NEPA compliance processes run concurrently and culminate in a Recommended Plan and Environmental Impact Statement (EIS) or Environmental Assessment.

- **Eliminate Off-Project Irrigator Participation** – The CAPP currently includes the study of measures to reduce the power rates for On-

Project and Off-Project irrigators. Although the Off-Project irrigators also experienced power rate increases with the expiration of the 2006 FERC relicensing, the Klamath Project currently has no authority to serve the Off-Project community; consequently, future CAPP studies would only pertain to the On-Project irrigators.

1.3 Background

The Reclamation Klamath Project was authorized by the Secretary in 1905. The Klamath Project is located in south central Oregon and northern California and provides water to approximately 210,000 acres of cropland in the Klamath Basin. It covers lands in Klamath County, Oregon, and Siskiyou and Modoc counties in northern California, as shown in Figure 1-1. The Off-Project area includes irrigated lands in Oregon on the watersheds of the Lost, Sprague, Williamson, and Wood rivers as shown in Figure 1-2.



Source: Klamath Water and Power Agency 2014a

Figure 1-1. Klamath Project Area

Figure 1-2. Off-Project Area

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, the largest of which was the Keno Canal. Reclamation recognized that in order to irrigate the land it was necessary to access inexpensive power for both drainage and pumping. Although Reclamation had a desire to develop power for the Klamath Project, the initial agricultural development costs were greater than anticipated and there was insufficient funding for power development.

Meanwhile, the California Oregon Power Company (COPCO) was providing power in the region and had planned additional hydropower development on the Klamath River that would rely on water supplies from Upper Klamath Lake. In 1917 COPCO, now PacifiCorp, approached Reclamation and proposed building a dam on Upper Klamath Lake to provide better water regulation for planned hydropower generation on the Klamath River. Reclamation entered into a 50-year contract for the construction and operation of Link River Dam on Upper Klamath Lake. COPCO built the dam and deeded ownership to Reclamation along with discounted power rates to the Klamath Project beneficiaries. In exchange, COPCO was given the right to regulate Upper Klamath Lake for hydropower generation. The contract protected irrigation rights and provided the Klamath Project water users with power rates locked in at 1917 levels. The contract was amended in 1956, featuring essentially the same power rates for an additional 50-year period, and this became a provision of PacifiCorp's Klamath Hydroelectric Project FERC operating license. Later in 1956, a separate COPCO contract provided Off-Project agricultural power users with reduced power rates similar to those of the On-Project users. 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 prevented it from doing so. The 1917 COPCO agreement allowed Reclamation to provide the Klamath Project with affordable power for Basin irrigators as intended.

The expiration of PacifiCorp's FERC license and the power contract in 2006 ended nearly 90 years of reduced or at-cost power rates for the Klamath On- and Off-Project irrigators. Since then power rates have increased from 0.3 to 0.75 cents per kilowatt-hour (¢/kWh) to tariff rates of approximately 9.7 ¢/kWh in Oregon and 12.9 ¢/kWh in California. With this change, the average water pumping cost on the Klamath Project is now $45 per acre compared to an average power cost of $2.25 per acre prior to the power contract's expiration.

The KBRA and Klamath Hydroelectric Settlement Agreement (KHSA) were signed on February 18, 2010 to address multiple water, power, and environmental resource conflicts within the Klamath Basin. Within the KBRA, the PWMP identified several programs and areas of study to provide affordable power to agricultural water users affected by the transition to tariff power rates. Under the KHSA, DOI committed to acquiring power from the Bonneville Power Administration (BPA) to serve all "eligible loads" within BPA's authorized geographic area, under the expectation that Federal power will be less expensive than full tariff power from PacifiCorp. The Klamath Basin Task Force, created by Oregon's congressional delegation in 2013 to address water and power issues in the Basin, concluded in its December 2013 draft report that replacing affordable power previously provided by PacifiCorp is critical to the economic sustainability of On-Project and Off-Project irrigators.

KBRA Legislation and Funding

Legislation to authorize and fund the KBRA was introduced in the 113th and 114th Congress, but did not pass. The KBRA itself expired December 31, 2015. KBRA parties are working to salvage the agreement and its objectives.

The KHSA, KBRA, and the related Upper Klamath Basin Water Settlement Agreement are collectively referred to as the Settlement Agreements. The Settlement Agreements represent broad, collaborative efforts among dozens of stakeholders to address water and power issues throughout the Klamath Basin. Although not a signatory to the KBRA, DOI has committed to support its objectives to the extent possible under existing authorities and funding.

PacifiCorp is the owner and operator of the power distribution network in the Klamath Basin and provides electrical power as an investor-owned utility (IOU). As an IOU, PacifiCorp is subject to the rules and regulations of the Oregon Public Utility Commission (OPUC) and the California Public Utilities Commission (CPUC), which require that retail power rates be fair and reasonable and allow PacifiCorp to make a reasonable return on its electrical system investment through approved OPUC and CPUC tariff rates.

KBRA Power for Water Management Program

The PWMP (KBRA Section 17) included provision by the KBRA signatories to address electricity power needs of the Basin irrigators. When instituted, the program will provide power for the Klamath Project and refuges, and movement of water for the On-Project Plan. The program goals include providing power cost security for sustainable agriculture (On- and Off-Project) at rates equal to or lower than other Reclamation irrigation projects. Major program elements include:

- Interim power sustainability prior to implementation of the KBRA power program
- Study of Federal (BPA and WAPA) power supplies
- Conservation and efficiency measures
- Renewable power

KBRA Section 17 specified that the program be defined in a Financial and Engineering Plan that must be approved by the Secretary and adopted by the PWMP Management Entity for the expenditure of any Federal appropriations for the KBRA.

PacifiCorp is not a signatory to the KBRA but is a signatory to the KHSA. Through the KHSA, PacifiCorp agreed to work in good faith to accomplish the goals of the PWMP. PacifiCorp has stated throughout the stakeholder engagement process of the IAIR that it desires continued ownership of its electrical distribution system in the Basin.

At such time as federal legislation provides authority and funding to implement the PWMP, the CAPP scope may expand to include implementation (Construction and Operation and Maintenance Phases for the Renewable Power Program as defined in FAC 09-01[2]) of the Renewable Power Program.

1.4 Supporting Studies

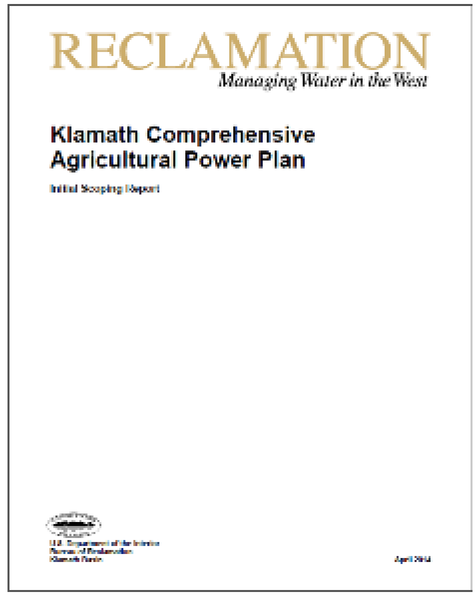
In developing the IAIR, Reclamation undertook three studies that helped assess whether the CAPP approach was viable and how a program of this magnitude might be undertaken. These studies are available at Reclamation's website,

[2] FAC 09-01, the Reclamation Manual's Directives and Standards for Cost Estimating, is available at http://www.usbr.gov/recman/fac/fac09-01.pdf

http://www.usbr.gov/mp/kbao/special_projects/power.html, and are summarized below.

Initial Scoping Report

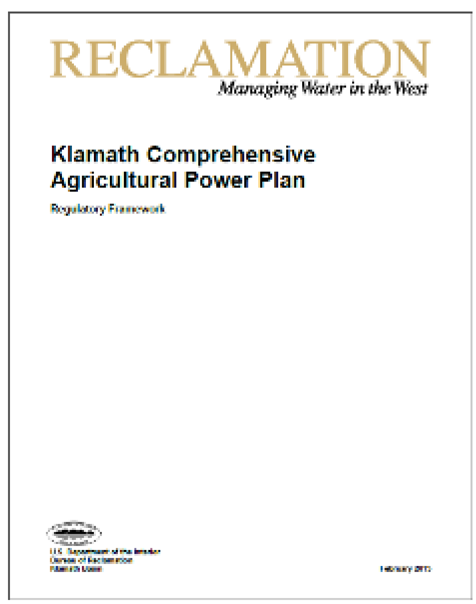
The Initial Scoping Report was undertaken to verify the validity of the proposed CAPP process as a means of reducing power costs or rates to Basin irrigators. The Initial Scoping Report documented case studies where irrigation districts in other locations throughout the western United States have implemented efficiency improvement or new power source development projects to reduce overall power costs. The Initial Scoping Report also reviewed the viability of various renewable power development options in the Basin including wind, solar, geothermal, hydropower, and biofuels.



The Initial Scoping Report identified many programs within western agricultural districts and agencies that were undertaken to reduce power use and cost. It also identified programs that experienced reduced power use as a benefit of reduced water use through system reoperation. The largest example identified is the 2001 Agricultural Peak Load Reduction Program conducted by the California Energy Commission (CEC). This program resulted in over 50 megawatts (MW) of peak load reduction and saved an estimated 16 million kilowatt-hours (kWh) of energy annually through agricultural system renovation and reoperation with a $6.5 million investment from the CEC. The report provided case studies where agencies are focused on renewable energy development that takes advantage of renewable energy incentive programs for the states' renewable energy portfolio standards.

Regulatory Framework Report

The CAPP Regulatory Framework Report identifies the electrical generation, transmission, and distribution requirements and restrictions under which PacifiCorp operates to provide Klamath Basin power in Oregon and California. This report also identified the potential new programs that PacifiCorp or a utility district could undertake to reduce Basin irrigation power costs. The Regulatory Framework Report established the programs that can and cannot be developed to reduce irrigator power costs without modifications to OPUC and CPUC policies and regulations.



Basin Pumping Efficiency

Reclamation undertook two studies to evaluate the efficiency and energy consumption of the large pumping equipment in the Klamath Basin's irrigation systems, referred to as Reserved and Transferred Works, and the approximately 2,500 private irrigation pumps. This work assessed the level of energy savings from pump reoperation and/or efficiency improvements. Surveys of the well owners were undertaken and a select number of representative pumps in the network of Reserved and Transferred Works and private pumps were field-tested for efficiency. The results of these studies demonstrated that substantial efficiency improvements could be made to the Reserved and Transferred Works and the private pumps, which would considerably reduce power costs.

1.5 Structure of this Report

This report is organized in the following chapters:

- **Chapter 1** provides background on the Klamath CAPP and the purpose of the IAIR.
- **Chapter 2** summarizes the stakeholder engagement program undertaken during the alternatives development process.
- **Chapter 3** summarizes the findings of the Klamath CAPP Regulatory Framework Report.
- **Chapter 4** presents the options development process and the CAPP options evaluated with the potential to lower delivered energy costs for Basin irrigators.
- **Chapter 5** presents the screening criteria and performance measures developed to evaluate CAPP options.
- **Chapter 6** presents the process used to formulate alternatives, describes the preliminary alternatives and their review with stakeholders, evaluates alternatives' performance against screening criteria, and summarizes the screening results.
- **Chapter 7** presents the final alternatives selected to move forward for further analysis.

Appendices to the IAIR include the following:

- Appendix A, References
- Appendix B, Klamath CAPP Regulatory Framework Report

- Appendix C, Klamath CAPP Private Pumps Field Testing Technical Memorandum
- Appendix D, Klamath CAPP Reserved and Transferred Works Field Testing Technical Memorandum
- Appendix E, Klamath CAPP Alternatives Economic Analysis

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Chapter 2
Stakeholder Program

An important element in the Initial Alternative Information Report's (IAIR's) development was the stakeholder engagement program undertaken at major decision points and milestones during the alternatives development process. Basin stakeholders were engaged in the Klamath Comprehensive Agricultural Power Plan (CAPP) planning process to develop alternatives that incorporated stakeholder input and that meet the stakeholders' and the Bureau of Reclamation's (Reclamation's) needs and objectives. The stakeholder engagement program included four stakeholder groups representing different levels of interest in and responsibility for the CAPP development:

- Steering Committee
- Technical Workgroup
- Stakeholder Focus Group
- Klamath Tribes

These groups provided feedback to Reclamation on strategies to develop power cost reduction options and participated in the development and review of CAPP work products. The process included representation from both On-Project and Off-Project irrigators and recognized whether a stakeholder was a signatory to the Klamath Basin Restoration Agreement. A description of each stakeholder group is provided in the sections below. Table 2-1 presents the schedule of stakeholder group involvement during the IAIR's development.

Table 2-1. Stakeholder Group Meeting Dates

Group	Aug	Sept	Nov	Feb	Apr	May	June	Aug
Steering Committee	Kickoff 8/15/14							
Technical Workgroup (TWG)		TWG 1 Kickoff 9/5/14	TWG 2 Baseline Inventory and Screening Criteria 11/19/14	TWG 3 Options Identification Workshop 2/20/15	TWG 4 Initial Options and Screening 4/17/15		TWG 5 Alternatives Formulation Workshop 6/10/15	TWG 6 Present Proposed Initial Alternatives 8/27/15
Stakeholder Focus Group (SFG)				SFG 1 Options and Screening Process 2/19/15		SFG 2 Options Evaluation and Alternatives Formulation Process 5/11/15		SFG 3 Present Initial Alternatives *
Klamath Tribes								Biomass Energy 8/26/15

* A newsletter/mailer will be sent out in early 2016 to all Basin stakeholders and posted on Reclamation's website in lieu of a meeting, due to schedule conflicts resulting from the seasonal farming practices.

2.1 Steering Committee

The Steering Committee served an advisory role in the development of the Klamath CAPP and included representatives from the Klamath Water and Power Authority (KWAPA), Klamath Basin Water Users, and Reclamation. The Steering Committee provided policy level input and guidance on members for the Technical Workgroup, as well as feedback from the Technical Workgroup on the technical adequacy and direction of the IAIR. Most of the feedback from the Steering Committee members was received individually or in small groups before and after Technical Working Group (TWG) meetings rather than through a formal meeting process.

2.2 Technical Workgroup

The Technical Workgroup provided technical and policy guidance on the IAIR development and provided input on irrigation operations and management to inform development and evaluation of options and alternatives. Participants in the TWG included Basin irrigators (On- and Off-Project) and state and Federal representatives with a direct interest in the Klamath CAPP.

TWG meetings were structured as interactive workshops to promote group discussions and input. Topics included irrigation equipment renovation, power options identification and screening criteria, alternatives development, and alternatives engineering and economics. Representatives from other agencies and organizations were asked to participate in meetings to provide selective feedback or technical presentations. These groups included the Federal Power Workgroup, Energy Trust of Oregon, the California Public Utilities Commission (CPUC), California Energy Commission, and PacifiCorp.

Each chapter in the IAIR presents a summary of the TWG's input during that stage of the planning process.

2.3 Stakeholder Focus Group

The Stakeholder Focus Group (SFG) offered an opportunity for stakeholders and the public interested in the CAPP to provide technical feedback on select IAIR work products. Stakeholders were defined as any interested party in the Basin affected by the transition to PacifiCorp tariff rates. The SFG meetings were held in Klamath Falls at venues capable of accommodating larger groups of attendees. Reclamation distributed more than 2,600 mailers announcing the meetings, sent e-mails to On- and Off-Project irrigators and districts, and posted meeting notifications on Reclamation's website.

The SFG meetings were structured with a formal presentation followed by an opportunity for attendees to ask questions. Topics covered included power cost reduction options and screening and initial alternatives. Participation was encouraged from:

- CPUC and Oregon Public Utility Commission (OPUC)
- Environmental organizations
- Farm organizations
- Federal, state, and local resource agencies
- Fisheries and wildlife organizations
- Individual On and Off-Project irrigation power users
- Irrigation and drainage districts (On- and Off-Project)
- Klamath Basin Tribes
- PacifiCorp
- Potential CEQA lead agency
- Refuge managers

2.4 Tribal Consultation

As a governmental process that could affect the Basin Tribes, formal government-to-government consultation was available to the Klamath Tribes. No formal consultation was requested by the Tribes during the IAIR process. A meeting was held with the Klamath Tribes on August 26, 2015 to discuss biomass energy development.

Chapter 3
Regulatory Framework

PacifiCorp, an investor-owned utility (IOU), is the owner and operator of the power distribution network in the Klamath Basin. As an IOU, PacifiCorp's California operations are regulated by the California Public Utilities Commission (CPUC) and its Oregon operations are regulated by the Oregon Public Utility Commission (OPUC). PacifiCorp is also subject to other state and Federal agencies, including the Federal Energy Regulatory Commission (FERC). This chapter identifies the regulatory framework under which PacifiCorp operates to provide Klamath Basin power in Oregon and California and identifies potential programs that PacifiCorp, or a utility district such as Klamath Water and Power Agency (KWAPA), could institute to lower energy costs to the Basin irrigators. A full evaluation of the regulatory framework for power development, transmission, and distribution, as well as the programs and policies that govern new power development and sales by a third party in Oregon and California, can be found in Appendix B, Klamath CAPP Regulatory Framework Report.

3.1 Major Regulatory Entities Affecting the CAPP

This section describes the major state and Federal regulatory entities with a role in power development and sales by a third party in Oregon and California.

3.1.1 OPUC

The OPUC regulates consumer rates and services for IOUs in Oregon. The OPUC's Utility Program "ensures consumers receive utility service at fair and reasonable rates, while allowing regulated companies the opportunity to earn an adequate return on their investment" (OPUC undated). The OPUC also has programs designed to set and enforce prices and has services that protect consumers. In addition, the OPUC evaluates many components of cost and decides the structure of customer rates. The OPUC requires its large IOUs, including PacifiCorp, to meet Oregon's Renewables Portfolio Standard (RPS) by procuring 15 percent of their power through renewables by 2015, 20 percent by 2020, and 25 percent by 2025.

3.1.2 Energy Trust of Oregon

Energy Trust of Oregon (Energy Trust) is an independent, non-profit organization that offers cash incentives and energy solutions to PacifiCorp customers in Oregon to reduce energy costs. Energy Trust is funded by the customers of Oregon IOUs (Portland General Electric, PacifiCorp, NW Natural, and Cascade Natural Gas) who pay a percentage of their utility bills to support the energy efficiency and renewable energy programs offered by Energy Trust. Energy Trust is overseen by the OPUC, which sets electric efficiency performance targets in certain regions of the state.

3.1.3 CPUC

The CPUC has authority over the operations of the California IOUs as well as PacifiCorp, and sets their retail rates through General Rate Cases. The CPUC serves the public interest by protecting the IOUs' consumers and ensuring the provision of safe, reliable utility service and infrastructure at reasonable rates. The CPUC is responsible for ensuring that IOUs meet California's RPS by procuring 20 percent of its power through renewables by 2010, 33 percent by 2020, and 50 percent by 2040.

3.1.4 California Independent System Operator

The California Independent System Operator (ISO) is an independent, non-profit grid operator that oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities. The ISO operates both a day-ahead and real-time energy market to ensure that adequate power is available at the lowest price to meet demand in its power Balancing Authority Area.

Unlike other IOUs operating in California, PacifiCorp is not an ISO member utility. PacifiCorp operates its own Balancing Authority Area and is not required to follow the ISO policies required of full ISO member utilities, including Direct Access competition where consumers can chose their energy provider. Pursuant to an agreement between the ISO and PacifiCorp approved by FERC in July 2013, PacifiCorp and the ISO recently implemented an energy imbalance market (EIM), which facilitates PacifiCorp's participation in an extension of the ISO's real-time balancing market that optimizes generation and transmission between the two service areas of the ISO and PacifiCorp. PacifiCorp's transmission interconnection with the ISO occurs though its major transmission lines that run through Klamath Falls and Malin (the California-Oregon Intertie). The EIM is expected to reduce customer costs through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrate renewables, and enhance reliability through improved situational awareness and responsiveness.

3.1.5 FERC

FERC is responsible for the interstate transmission of power and large power development. FERC requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to provide open access transmission tariffs (OATTs) that contain the terms and conditions of non-discriminatory transmission service to all transmission customers, including independent power developers. Open access transmission facilitates competition in the wholesale power marketplace, resulting in lower power costs for electricity consumers.

PacifiCorp maintains OATTs for generator interconnections and transmission services. Requests for generator interconnections or transmission services are managed through PacifiCorp Transmission Service's Generation Interconnection Queue. PacifiCorp maintains a formalized process to study and interconnect new power development under this OATT, including any new Qualifying Facilities developed in the Klamath Basin.

The OATT defines the terms and conditions governing access to PacifiCorp's transmission system. A request for transmission service would result in a study to determine available transmission capacity and to determine applicable costs for any potential system upgrades necessary to transmit power from a resource developed in the Basin that utilizes PacifiCorp's transmission system.

FERC's Department of Energy is responsible for the Public Utility Regulatory Policy Act (PURPA), which creates a market for power from non-utility power producers referred to as "Qualifying Facilities." PURPA requires utilities such as PacifiCorp to buy power from independent qualifying generation facilities at the avoided cost rate, the rate it would cost the utility to generate the power itself. PURPA provides the mechanism whereby Qualifying Facilities, if developed in the Basin, would sell power to PacifiCorp at its avoided cost.

3.2 PacifiCorp Operations

This section describes the current electrical service programs offered by PacifiCorp in Oregon and California. PacifiCorp's operating requirements and programs under the OPUC and CPUC vary substantially between the two states. A summary of PacifiCorp's operations in Oregon and California is provided below.

3.2.1 Oregon

PacifiCorp currently offers Oregon irrigators several rate schedules. Schedule 41 is the primary irrigation rate schedule, with a combined effective summer rate of 9.674 cents per kilowatt-hour (¢/kWh) for all services and OPUC charges. Schedule 741 is PacifiCorp's Direct Access competitive rate schedule, which reduces Schedule 41 by 3.181 ¢/kWh because energy is supplied by an electricity service supplier (ESS). The ESS provides competitive electricity and would need to offer a rate lower than 3.181 ¢/kWh for consumers to see a reduction in their power rate. For all schedules, a basic charge of $1,210 is annually charged to loads exceeding 300 kilowatts (kW), approximately the load of a 400-horsepower pump. An annual load size charge is also included in all schedules.

PacifiCorp also provides rate schedules for off-peak power and net metering programs. The off-peak programs, Schedules 210 and 215, provide a credit for energy used during off-peak hours and an additional charge for energy used during on-peak hours. Schedule 210 has seasonal on-peak pricing while Schedule

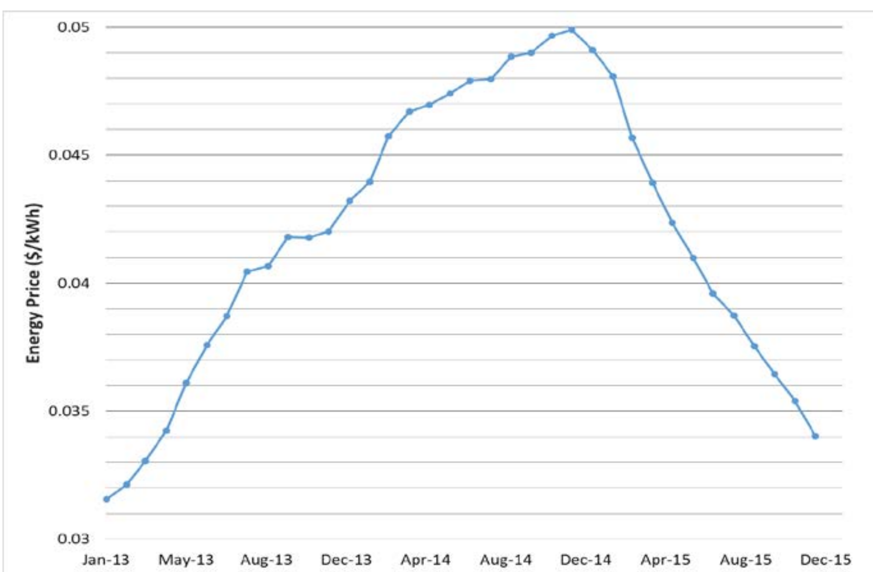
215 does not. Schedule 215 is in a pilot stage with the OPUC, with a cap on participation. PacifiCorp's net metering program, Schedule 135, offsets energy costs of customers who generate up to 2,000 kW of renewable energy on-site, but does not compensate a generator for net excess annual energy production. Energy Trust currently offers PacifiCorp customers incentives of up to $76,000 per project for solar photovoltaic (PV) installations.

PacifiCorp provides Schedules 37 and 38 for pricing new power generation from Qualifying Facilities that feed into PacifiCorp's transmission and delivery system, paying the generator its avoided cost rate (2015 rates are 2.19 ¢/kWh off-peak and 2.77 ¢/kWh on-peak). Schedule 37 services Qualifying Facilities with a nameplate capacity of 10,000 kW or less, while Schedule 38 services those with capacities greater than 10,000 kW and up to 80,000 kW.

3.2.2 California

PacifiCorp currently offers California irrigators one rate schedule (Schedule PA-20), with a combined effective rate of 12.933 ¢/kWh for all services and CPUC charges. Schedule PA-20 includes an annual load charge of $149.31 plus a $15.63/kW load charge for loads exceeding 50 kW.

PacifiCorp offers a net metering program, Schedule NEM-35, capped at 1,000 kW, under which customers with on-site renewable generation systems are compensated for net excess electricity generated at a rate equal to the simple rolling average of Pacific Gas and Electric Company's (PG&E) default load aggregation point (DLAP) price. This price changes from month to-month, but was 3.96 ¢/kWh in July 2015. Figure 3-1 shows PG&E's monthly DLAP prices from January 2013 to December 2015.



Source: PG&E 2015a

Figure 3-1. PG&E DLAP Prices 2013-2015

PacifiCorp also offers the California Solar Incentive Program (CSIP), which provides a rebate to customers who install a solar PV system in California ($0.36/Watt for residential and $1.11/Watt non-residential). CSIP, which began in 2011, is a limited program with approximately 3,500 kW of total capacity. As of July 30, 2015 the program has 141 kW of available capacity for residential customers with 53.6 kW currently under review (approximately 87.6 kW remaining) and 336 kW available for non-residential customers (PacifiCorp 2015a). Eligible projects are capped at 250 kW. CSIP is scheduled to conclude March 10, 2016.

PacifiCorp does not have any programs for new power development in California. New power development would fall under the general requirements of PURPA as a Qualifying Facility (as discussed above), requiring PacifiCorp to compensate the generator for power at its avoided cost rate.

In February 2015 PacifiCorp filed a request with the CPUC to establish a time-of use pilot program similar to that offered in Oregon which, if approved, would provide participating irrigation customers on Schedule PA-20 in the Tulelake area with a 4.254 ¢/kWh credit for energy used during off-peak hours and a 30.022 ¢/kWh additional fee for energy used during on-peak hours. If approved, the pilot would be available for the 2016 irrigation season and participation would be limited to 25 meters.

Table 3-1 presents the current electrical service schedules and energy charge rates offered by PacifiCorp in Oregon and California.

Table 3-1. Current PacifiCorp Energy Charge Rates

	Schedule	Load Limit	Total Rate (¢/kWh)	Annual Load Size Charge	Annual Basic Charge	Comment
OR	41/741	<1,000 kW	9.674	Loads ≤ 50 kW: $15/kW 3-Phase loads 50-300 kW: $10 /kW 3-Phase loads > 300 kW: $6/kW	≤50 kW: No Charge 51-300 kW: $310 >300 kW: $1,210	Summer with secondary voltage Direct Access Competitive rate is 3.181 ¢/kWh.
OR	210	<30 kW	On-Peak Summer: 8.004 On-Peak Winter: 3.737 Off-Peak: -1.231	See Schedule 41/741	See Schedule 41/741	Rates are added or subtracted from the Schedule 41 rates.
OR	215 Pilot program	<1,000 kW	On-Peak: 22.313 Off-Peak: -3.161	See Schedule 41/741	See Schedule 41/741	Rates are added or subtracted from the Schedule 41 rates.
CA	PA-20	<500 kW	12.933	All Loads: $15.63/kW plus Loads <50kW: $72.28 3-Phase loads >50 kW: $149.31	≤50 kW: $72.28 >50 kW: $149.31	Includes the 8.216 ¢/kWh tariff rate and PUC surcharges.

Notes:
¢/kWh = cents per kilowatt-hour; kW = kilowatt
Rates may not include all CPUC- and OPUC-required charges.
Winter is defined as November 1 through March 31, and summer as April 1 through October 31.
Annual Load Size Charges are based on the peak load recorded.
300 kW is equivalent to a 400 horsepower pump. 50 kW is equivalent to a 66 horsepower pump.

3.3 Progressive Power Development

Four programs available in California and Oregon could provide the Klamath Basin with opportunities for reduced energy costs if supported by PacifiCorp and adopted by the PUCs. Three of these opportunities are available in California, although not in PacifiCorp's service territory, and the last is a newly passed law in Oregon.

3.3.1 Local Government Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) Program

The RES-BCT program was established in California in 2008 and authorizes local governments such as cities, counties, or other local public agencies to generate renewable energy on-site under one account and transfer excess bill credits to up to 50 other accounts (Benefiting Accounts) in the same geographical boundary owned or operated by the same local government. A local government may own multiple Generating Accounts, each with a limited capacity of 5,000 kW.

Currently the RES-BCT program has a total of 30,884 kW operating at several facilities under a state-wide cap of 250,000 kW (PG&E 2015b, Southern California Edison 2015, San Diego Gas & Electric 2015).

3.3.2 Green Tariff Shared Renewables Program

The Green Tariff Shared Renewables Program was established in California in 2013 and provides businesses and individuals the ability to purchase 100 percent renewables through their utility. The program makes it possible for customers who cannot generate their own renewable energy on-site to contribute and use virtual renewable energy sources guaranteed through the utility.

3.3.3 Community Choice Aggregation

Community Choice Aggregation (CCA) provides cities and counties the ability to aggregate electric loads of residents, businesses, and public facilities to facilitate the purchase and sale of renewable energy. Under this system there is greater local control, but transmission tariffs are still recovered by the utility owning the transmission and delivery system. As an example, Sonoma County in California created a CCA (Sonoma Clean Power) that offers locally sourced, renewable power to the entire county at a lower cost than PG&E (the county's regulated utility).

3.3.4 Renewable Energy Cooperative Corporations

Oregon's Senate Bill 1520, Renewable Energy Cooperative Corporations, provides Oregon irrigators the ability to pool resources with an energy cooperative and develop renewable energy, such as solar PV, with the sale of the energy to the hosting entity. For example, a renewable energy cooperative could raise funding for, build, and certify a solar power production facility that delivers energy or economic benefit to its members. Power generated from this facility could be used to directly offset power costs, and the remaining power could be sold to the local utility to provide dividends to its members, which can then be credited against their power bills. In PacifiCorp's service area, the energy cannot be used directly by the cooperative's members.

3.4 Federal Power

To address the goals of the Klamath Basin Restoration Agreement (KBRA) Power for Water Management Program, the Federal Power Delivery Workgroup (Workgroup) composed of Basin water agencies, the Bureau of Reclamation (Reclamation), PacifiCorp, Bonneville Power Administration (BPA), and Western Area Power Administration (WAPA) was formed to identify the process for delivering Federal power to the Basin irrigators. The Workgroup determined that distributing Federal power to Basin loads would require Reclamation to take the contractual program lead with BPA. The Workgroup estimated that only 50 percent of the Oregon loads would experience a maximum of 10 percent reduction in rates through Federal power supplied by BPA.

WAPA does not have any available power to serve California loads, and passage of authorizing legislation for the KBRA would be necessary to serve Off-Project loads.

3.5 Energy Cost Reduction Opportunities and Constraints

This section summarizes the regulatory opportunities and constraints for reducing energy costs to Klamath Basin irrigators. Numerous opportunities to reduce energy costs exist; however, many have associated challenges to implementing the opportunities in the Basin which are generally related to state regulations and PacifiCorp operations. Table 3-2 presents the energy cost reduction opportunities and their associated constraints applicable to Oregon, California, and the two states collectively.

One substantial challenge to a Basin-wide energy cost reduction program is the differing Oregon and California regulations. As Table 3-2 shows, the Oregon and California programs have substantial differences. Promising programs in one state are not available or are different in the other state. A uniform set of policies that govern the Oregon and California portions of the Klamath Project would be ideal.

Table 3-2. Cost Reduction and Power Development Opportunities and Constraints

Oregon Opportunities	Constraints
Net metering allows customers to generate up to 2,000 kW and send excess generation back onto the grid. Energy Trust provides incentives up to $76,000 for new solar installations.	• Does not allow virtual metering • Restricted to one property owner or entity (irrigation district) • No reimbursement for annual overproduction
Off-Peak rate programs offer customers lower rates during off-peak hours and additional charges during on-peak hours.	• On-peak pilot rate adds 22 ¢/kWh • Pilot is limited to 3 meters per owner • Pilot continuation and future rates are uncertain
Federal power provided through BPA supplies energy to Oregon load with usage >17,000 kWh annually (approximately 50 percent of meters) or load to select meters with future price stability.	• Cost is comparable to the current Schedule 41 rate • Energy Trust incentives are suspended • Requires new metering
ESS provides competitive energy delivered over PacifiCorp's distribution system.	• Requires separate billing for supply (ESS) and distribution (PacifiCorp)
California Opportunities	**Constraints**
Net metering allows customers to generate up to 1,000 kW and send excess generation back onto the grid. Customers can receive reimbursement for annual overproduction.	• Does not allow virtual metering • Restricted to one property owner or entity
RES-BCT allows local governments to generate renewable energy on-site under one account and transfer excess bill credits to other accounts.	• PacifiCorp is not required to offer this program
Green Tariff Shared Renewables allows individuals to purchase 100 percent of energy supply from renewables.	• PacifiCorp is not required to offer this program
CCA allows renewable power development and virtual metering within an IOU's distribution system. Rates are set by the aggregator, but subject to IOU transmission fees.	• PacifiCorp is not required to offer this program
Opportunities Common to Oregon and California	**Constraints**
Pump efficiency improvements paid for partially through available cash efficiency incentives from Energy Trust in Oregon and PacifiCorp in California.	
PURPA Qualifying Facility development for new power generation sources using the most economical energy source and best technology.	• Sold to PacifiCorp at avoided cost rate • KBRA funding specifies renewables; most cost efficient Qualifying Facilities use natural gas
Distribution System Ownership/Operation by a basin people's utility district (PUD) or electrical cooperative provides greater ability to set rates and generate and distribute power.	• PacifiCorp has stated it has no interest in selling its distribution assets in the Klamath Basin.

Technical Workgroup Meeting #2

Technical Workgroup (TWG) Meeting #2 was held on November 19, 2014 in the KWAPA/Klamath Water Users Association conference room in Klamath Falls, Oregon. A webinar was held simultaneously for those who could not attend in person.

Purpose

The purpose of this meeting was to review the CAPP scope of work, discuss the preliminary results of pump efficiency evaluations, and present the findings of the CAPP Regulatory Framework Report.

Major Outcomes and Decisions

The TWG provided feedback to the technical team stating that the CAPP should not focus on efficiency and equipment upgrades, but on new power development options with the potential to reduce delivered power rates. Efficiency work was described as work the irrigation community could pursue independently.

A substantial finding of the CAPP Regulatory Framework Report was the very different operational regulations under the CPUC and the OPUC. The question was posed whether a more uniform set of regulations covering the Oregon and California Project area was possible by working collaboratively with PacifiCorp, CPUC, and OPUC. A representative of PacifiCorp suggested this would be a substantial challenge given the different regulations in each state.

Relative to the CAPP scope of work, the project objectives were modified as follows:

- Develop a Financial and Engineering Plan for renewable power projects, including efficiency and National Environmental Protection Act (NEPA) compliance for expenditure of Federal Klamath Basin Restoration Agreement (KBRA) funds.
- Achieve an equitable distribution of benefits among beneficiaries.
- With assumed KBRA funding of $40-$50 million, define a suite of least-cost power development options with the potential to reduce agriculture’s delivered power costs to levels at or below the average of other Reclamation irrigation projects.

Chapter 4
Description of Options

Many options available in the Klamath Basin have the potential to lower the delivered energy costs for Basin irrigators, including power development and generation and load reduction and demand management options. This chapter provides a description of the overall options development process and identifies the Klamath Comprehensive Agricultural Power Plan (CAPP) options evaluated throughout the process.

4.1 Options Development Process

The investigation of the regulatory framework for power development and sales by third parties in Oregon and California (summarized in Chapter 3) revealed a number of programs and mechanisms with the potential to reduce the delivered power rates of the Klamath Basin irrigation community. An initial list of options with the potential to lower energy costs to Basin irrigators was developed through the collaboration of the technical team, the Technical Workgroup (TWG), and stakeholders. The technical team and members of the TWG solicited stakeholders for additional suggestions of options to be considered in the CAPP.

Based on TWG and stakeholder input, CAPP options were separated into two categories: 1) power development and 2) load reduction and demand management. Power development options focused on technologies and mechanisms that would allow for the generation and sale of power to PacifiCorp through a power purchase agreement (PPA) with the understanding that the revenue generated would be used to provide Basin irrigators with credits to their energy bills, lowering their overall delivered energy costs. Furthermore, the group came to a consensus that power generation technologies would not be limited to renewable options regardless of the language in the Klamath Basin Restoration Agreement (KBRA), which specifies funding as available solely for renewable technologies[3]. Load reduction and demand management options focused on programs and funding mechanisms that would enable irrigators to reduce their delivered energy costs by lowering their energy use and shifting demand timing.

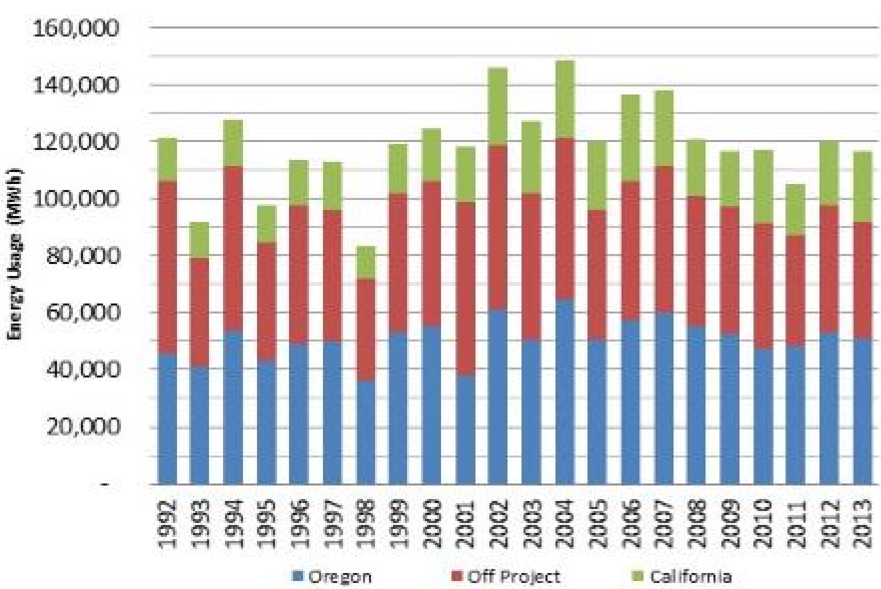
[3] An amendment to the KBRA would be needed to include funding for non-renewable energy technologies. The level of effort and the likelihood of successfully amending the KBRA were not addressed in this report.

As part of the options development process, the Bureau of Reclamation (Reclamation) reviewed Basin energy use through data provided by PacifiCorp from 1992 to 2013 for the purpose of understanding how various regulations and programs with power development and energy use thresholds can be applied to reduce energy costs to Basin irrigators. Figure 4-1 shows energy use in the Basin peaked at approximately 150,000 megawatt-hours (MWh) in 2004, with the lowest energy use in 1998 at about 82,000 MWh.

Definition of Power and Energy

Power and energy are related, but not synonymous. Power is the instantaneous ability to do work and is typically measured in watts. Energy is the amount of work done over a period of time (power used over time) and is typically measured in watt-hours. A useful analogy is that a 60-watt light bulb uses 60 watts of power and 1,440 watt-hours of energy over a 24-hour period. Another key difference is that energy is delivered, while power is the rate at which the energy is delivered. Because energy costs are a function of both power (for example, demand charges and peak load) and energy (total energy consumption), both energy use and power demand are important factors in considering the different regulations and programs that may help reduce energy costs to Basin irrigators.

For CAPP options and alternatives, a baseline was developed that averages energy use from 2007 to 2013 and removes high energy use periods prior to 2007, when greater agricultural water diversions from the Klamath River were allowed. Table 4-1 identifies the baseline for future energy use and power demand for the three sectors of the Basin. This baseline was used to determine the energy cost reductions of the various options and alternatives discussed here and in Chapter 6.



Source: PacifiCorp 2014

Figure 4-1. Klamath Basin Energy Use from 1992 to 2013

Table 4-1. CAPP Baseline Energy Use and Power Demand

Sector	Energy Use (MWh)	Peak Power Demand (MW)
Oregon On-Project	52,000	47
Oregon Off-Project	44,000	30
Oregon Total	96,000	--
California On-Project	22,000	29
Total	118,000	--

Source: PacifiCorp 2014

4.2 Power Development Options

CAPP power development options focused on renewable and non-renewable power generation technologies that would allow for the generation and sale of power to a utility such as PacifiCorp through a PPA, with the understanding that the revenue generated would be used to provide Basin irrigators with credits to their energy bills, lowering their overall delivered energy costs. This section provides descriptions of each power development option evaluated by the CAPP.

The power generation options that may be applicable and feasible in the Klamath Basin include the following:

- Low-head hydropower
- Solar photovoltaic (small- and utility-scale)
- Wind (small- and utility-scale)
- Geothermal
- Biofuels
- Cogeneration (renewable and non-renewable combined heat and power)

4.2.1 Low-Head Hydropower

Low-head hydropower (hydro) can often be installed on existing water features including smaller dams, canals, irrigation drops, and even run-of-river from small diversions. The Klamath Basin has several potential sites for low-head hydro including PacifiCorp's Keno Dam, Eastside and Westside Powerhouses, and Klamath Project irrigation canals and conduits. Currently there are no low-head hydro sites identified in the California area of the Klamath Basin.

Benefits

The ability to generate power regardless of the time of day makes hydropower especially beneficial for power users with inconsistent or continuous daily power usage. Also, the seven months of the year when water is typically available in Klamath Project irrigation canals and conduits encompasses the summer irrigation season, when power is needed for agricultural pumping.

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. FERC does not have jurisdiction over federally owned hydropower projects.

Constraints

Barriers to widespread development of low-head hydro in the Basin include generation limits, transmission of generated power, and environmental impacts. Current regulatory policies in both states limit the generation of renewable energy to no more than 80,000 kilowatts (kW) for Qualifying Facilities. 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 must interconnect to new or existing distribution or transmission lines to transmit generated power. The cost of interconnection depends on the project size and the length of the 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.

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 with dam removal.

It is also worth noting that low-head hydro placed in irrigation canals would likely be controlled by an irrigation district, similar to the operations of the Klamath Irrigation District (KID) low-head hydro plant on Canal C, with the benefits accruing to the irrigation district. In addition, water is typically available in the canals and conduits for only seven months out of the year, increasing the cost per kilowatt-hour (kWh) generated and making it more difficult to recapture the initial capital costs.

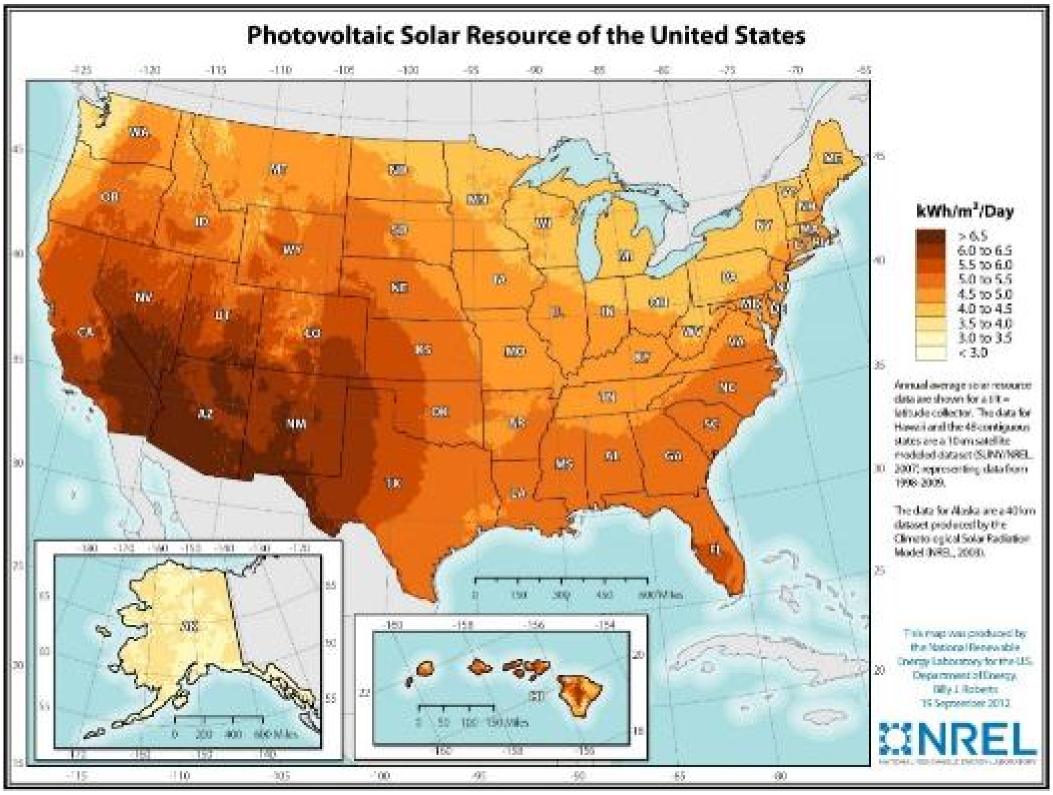
Financial Considerations

The *Capital Cost Review of Power Generation Technologies* provides reviews of several technologies and is recommended for comparison of potential renewable power projects (Western Electric Coordinating Council [WECC] 2014). From this report, the recommended capital development cost for small hydroelectric plants (run-of-river plants at 26 MW or smaller with no major dam or diversion work) is $4,000/kW. This development cost does not include the cost of interconnection, environmental permitting, or land costs. The levelized cost of energy (LCOE), a calculated cost of generating electricity at the point of connection to the electrical grid, is estimated at 1.98 cents per kWh (¢/kWh) for low-head hydropower. This value can be used to compare various technologies as well as the purchase price a developer would receive from the connected utility.

Power generated at these facilities could be sold to PacifiCorp through a PPA at the avoided cost rate. PacifiCorp’s 2015 avoided cost rates are 2.19 ¢/kWh and 2.77 ¢/kWh for off-peak and on-peak, 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.

4.2.2 Solar Photovoltaic

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 4-2. This map indicates that solar PV development is very feasible in the Klamath Basin, with solar intensity ranging from 5.0 to 6.0 kWh per square meter per day.



Source: NREL 2012

Figure 4-2. Photovoltaic Solar Resources of the United States

The most conducive sites for solar PV development should meet the following criteria:

- Proximity to loads: Can the solar PV generation be used by loads close to the PV array?
- Site location: Is the site open to the south or southwest without tree cover?
- Site geography: Is the site relatively flat or does it slope slightly to the south or southwest?
- Local microclimate: Is the site prone to fog or flooding that would limit solar irradiance or flood electrical components?
- Local power distribution: If a larger, utility scale project is proposed, is the site close to power distribution lines?

Benefits

Small-Scale

Small-scale solar PV systems could be privately owned by individuals, businesses, or even by a small community. These small PV installations typically have relatively small footprints, could be roof-mounted or ground-mounted, and could be fixed or use tracking systems that move with the sun during the day. Although more expensive than fixed systems, tracking systems provide increased daily energy generation by capturing early morning and late afternoon energy. The power produced by small solar PV systems directly offsets the power supplied by a utility, reducing the individual's delivered power demand and overall energy costs.

Small-scale solar PV systems could be net metered under PacifiCorp's Schedule 135 in Oregon and Schedule NEM-35 in California, providing the individual with an energy credit per kWh of generated energy equal to the energy rates specified in their service tariff (Schedule 41 at 9.674 ¢/kWh or PA-20 at 12.933 ¢/kWh in Oregon and California, respectively). Additionally, in California PacifiCorp will provide compensation for any net excess energy provided by the individual's solar PV system after a 12-month period.

Utility-Scale

Utility-scale solar PV installations are those greater than 2,000 kW in Oregon and 1,000 kW in California. Power generated from these installations could be sold to PacifiCorp through a PPA, pursuant to the Public Utility Regulatory Policy Act (PURPA). PURPA requires utilities to purchase power generated by qualified facilities at the utility's avoided cost.

Constraints

Small-Scale

Small-scale solar PV systems have relatively few constraints. The major constraint is that the solar power is only produced during daylight hours, limiting the PV power available to offset the user's power demand. Generally solar power generation occurs between 9:00 am and 3:00 pm, an annual, averaged range that accounts for the increased amount of daylight hours in summer months, decreased hours in winter months, and daylight saving time shifts. Another constraint is that typical solar PV systems for agricultural pumping are ground-mounted; depending on the system size, some farmland may be sacrificed. For example, a 100-kW system would require approximately three-quarters of an acre for the PV array and power collection system.

In addition, PacifiCorp's Oregon net metering program does not compensate for net excess power generation at the end of a 12-month period. Any remaining net excess energy credits would be donated to PacifiCorp's low-income assistance program.

Utility-Scale

Utility-scale solar typically requires large land areas and long-term maintenance, and the output of the system must be connected to a nearby distribution or transmission line, generally at 4 kilovolts or higher. Site locations may be limited, based on the existing power grid, to avoid excessive interconnection costs. As with small-scale solar, power is only produced during daylight hours, generally 9:00 am to 3:00 pm, limiting power generation.

Financial Considerations

Capital development costs for solar installations have declined significantly over the past few years, and further significant cost reductions are anticipated. The recommended capital development cost for small- and utility-scale solar installations is $3,800/kW and $2,600/kW, respectively. These development costs do not include interconnection, environmental permitting, or land costs. As an example of the solar development cost, Table 4-2 displays the solar capacity and cost necessary to serve approximately 50 percent of the Basin's agricultural energy usage. The LCOE is estimated at 1.98 ¢/kWh for small-scale solar and 1.89 ¢/kWh for utility-scale solar. These LCOEs can be used to compare various technologies as well as the purchase price a developer would receive from the connected utility.

Table 4-2. CAPP Baseline Energy Use, Power Demand, Solar Capacity, and Cost

Sector	Energy Use (MWh)	Solar Capacity for 50% MWh Supply (MW)	Cost of Solar PV Power for 50% Supply ($)
Oregon On-Project	52,000	17	$44.2M
Oregon Off-Project	44,000	14	$36.4M
California On-Project	22,000	7	$18.2M
Total	118,000	--	$98.8M

Small-Scale

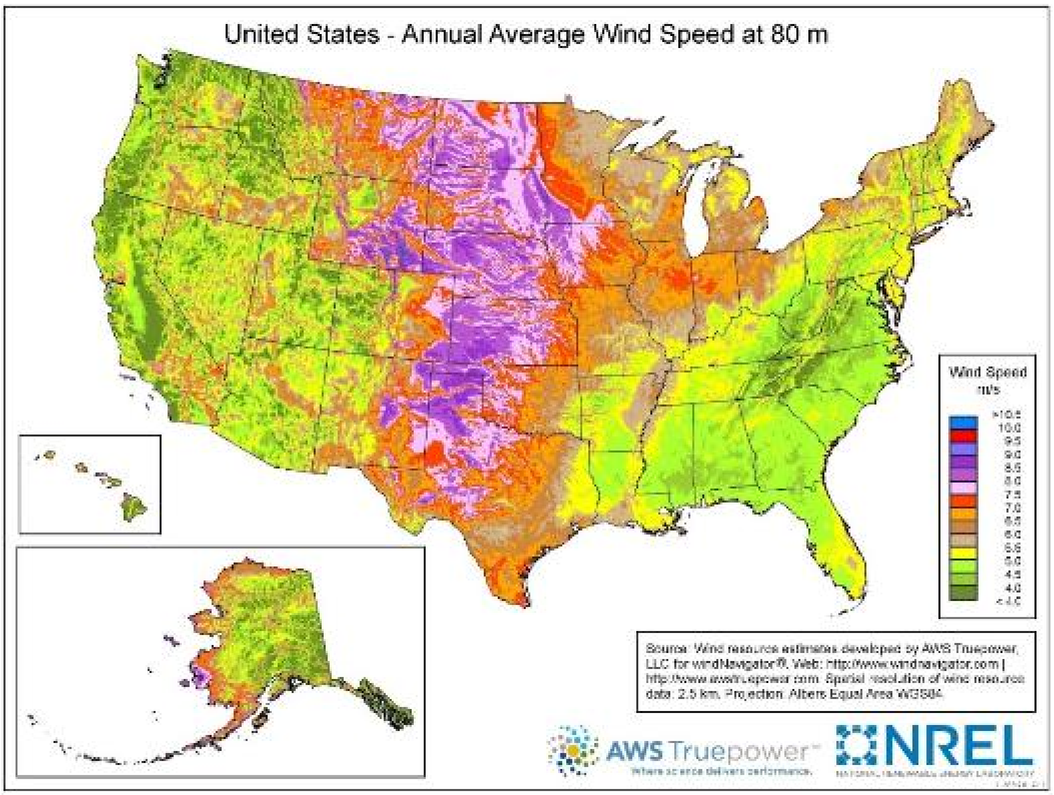
Small-scale solar PV systems could be net metered under PacifiCorp's Schedule 135 in Oregon and Schedule NEM-35 in California. Net metering in Oregon would provide irrigators with the opportunity to directly offset the 9.674 ¢/kWh energy rate for power supplied by PacifiCorp for every kWh produced by the solar PV system. In California, irrigators could directly offset the 12.933 ¢/kWh energy rates and PacifiCorp will provide compensation (at the DLAP price) for any net excess energy provided by the individual's solar PV system after a 12-month period.

Utility-Scale

Power produced by utility-scale solar PV systems could be sold to PacifiCorp through a PPA starting at its avoided cost (2015 rates are 2.19 ¢/kWh off-peak, and 2.77 ¢/kWh on-peak) in both Oregon and California.

4.2.3 Wind

Wind energy is extremely site-dependent; the site must be fairly windy throughout a large portion of the year. Figure 4-3 displays the annual average wind speeds in the United States. Northern California currently experiences wind speeds ranging between 4.0 and 6.5 meters per second (m/s) at a height of 80 meters. Southern Oregon currently experiences speeds ranging from 4.0 to 7.0 m/s at a height of 80 meters. The more economical utility-scale wind energy projects have annual average, hub height wind speeds of at least 6 m/s. While Northern California and Oregon have some locations with higher annual average wind speeds, it is likely that these areas are not collocated with the irrigators.



Source: NREL 2011

Figure 4-3. Annual Average Wind Speed in the United States

The most cost effective potential sites for wind development should include the following characteristics:

- Consistent wind
- Access to electrical loads or power distribution lines
- Located away from large populations of birds or water fowl flyways

Small-Scale
Small wind turbines of less than 100 kW can be sited on individual properties and net metered, similar to small-scale solar.

Utility-Scale
Available wind resource data indicates that development of utility-scale wind energy in the Klamath Basin area is not promising. Wind projects have not been developed in the Basin primarily because the wind resource is not available.

Benefits
If suitable sites are identified, the power generated from small wind turbines could be net metered by individual irrigators under PacifiCorp's Schedule 135 in Oregon and Schedule NEM-35 in California. Compensation from net metered wind would be the same as described for net metered solar PV.

Constraints
Optimal wind power generation sites may exist in remote areas, where the land may have more highly valued uses that are not compatible with wind turbines. More important, power can only be generated under certain wind-speed conditions. Due to the wide variability of wind speeds, wind power cannot be used as a baseload power source and the hours of generation may not coincide with agricultural power demand.

There are several national wildlife refuges in the Klamath Basin that serve the Pacific Flyway for migratory birds, including many listed Endangered Species Act species. Utility-scale wind power generation projects would need to be located away from these bird-populated areas.

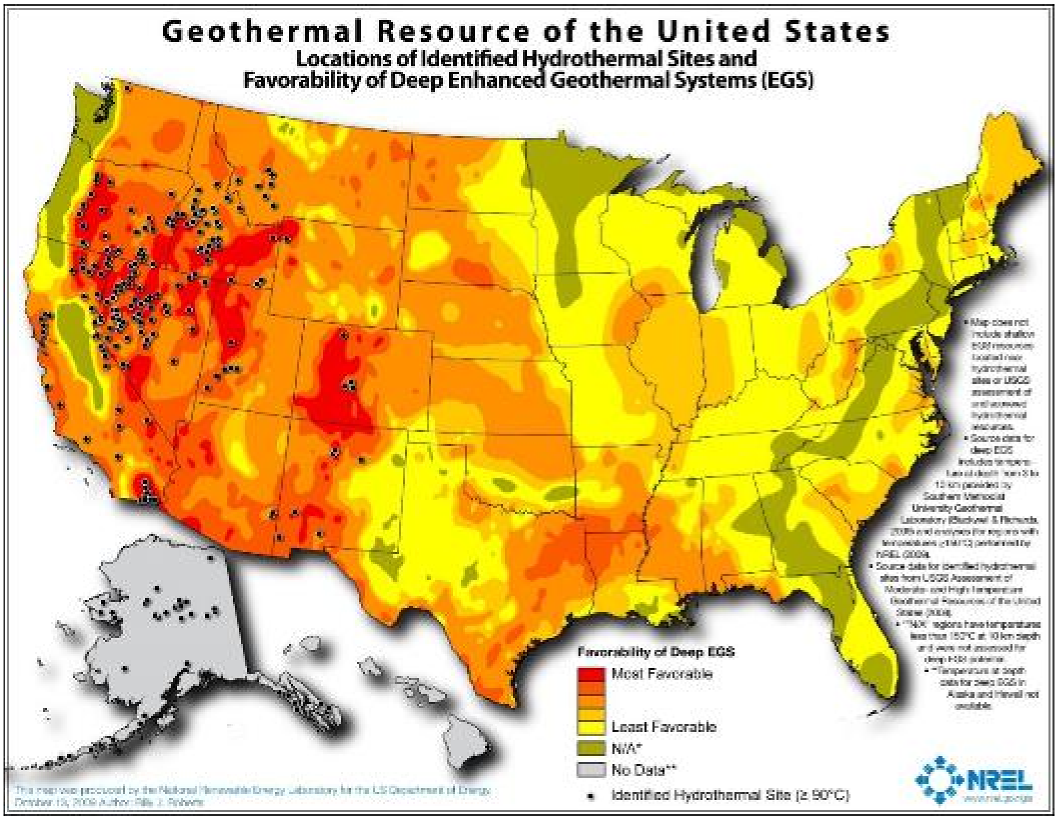
Financial Considerations
The recommended capital development cost for utility-scale wind installations is $2,100/kW (WECC 2014). This development cost does not include interconnection, environmental permitting, or land costs. The LCOE is estimated at 4.76 ¢/kWh, and can be used to compare various technologies as well as the purchase price a developer would receive from the connected utility.

Capital costs for small wind turbines (up to 100 kW) are typically in the range of $6,000 to $9,000 with larger turbines generally having the lower cost per kW (U.S. Department of Energy 2015).

As a region with lower wind speeds, it is unlikely that a utility-scale wind farm would be financially feasible in the Klamath Basin.

4.2.4 Geothermal
The Klamath Basin covers an area that has demonstrated geothermal potential, as shown in Figure 4-4. Technological advances have enabled electrical generation from geothermal heat sources that previously would not have been considered viable due to the insufficient pressure and temperature of the geothermal fluids to

be used as an energy source. With this new technology as well as the more traditional flash steam technology, geothermal development in the Klamath Basin is currently being undertaken, with at least one known project negotiating power sales with PacifiCorp.



Source: NREL 2009

Figure 4-4. Geothermal Resources in the United States

Benefits

Electricity produced from geothermal energy is relatively clean, producing only about one-sixth of the carbon dioxide (CO_2) of a natural gas-fueled power plant and little to no nitrogen oxides or sulfur-bearing gases. Additionally, geothermal power plants typically run with greater than 90 percent availability, 24 hours a day, 365 days a year, with no fuel costs (Office of Energy Efficiency and Renewable Energy 2015). The power can be used for base and scheduled loading. Generated power could be sold to PacifiCorp at its avoided cost under Schedules 37 or 38.

Constraints

Resource uncertainty and high development and exploration costs are barriers to development of geothermal power. Identifying and developing these resources is expensive and for various geologic reasons these resources tend to be in areas of low population, which are often distant from existing electrical distribution facilities, resulting in higher interconnection costs.

Geothermal energy is completely dependent on resource location and requires a unique geologic setting, such that steam or hydrothermal fluids of sufficient temperature and pressure occur in the subsurface at a shallow depth that would promote economic feasibility.

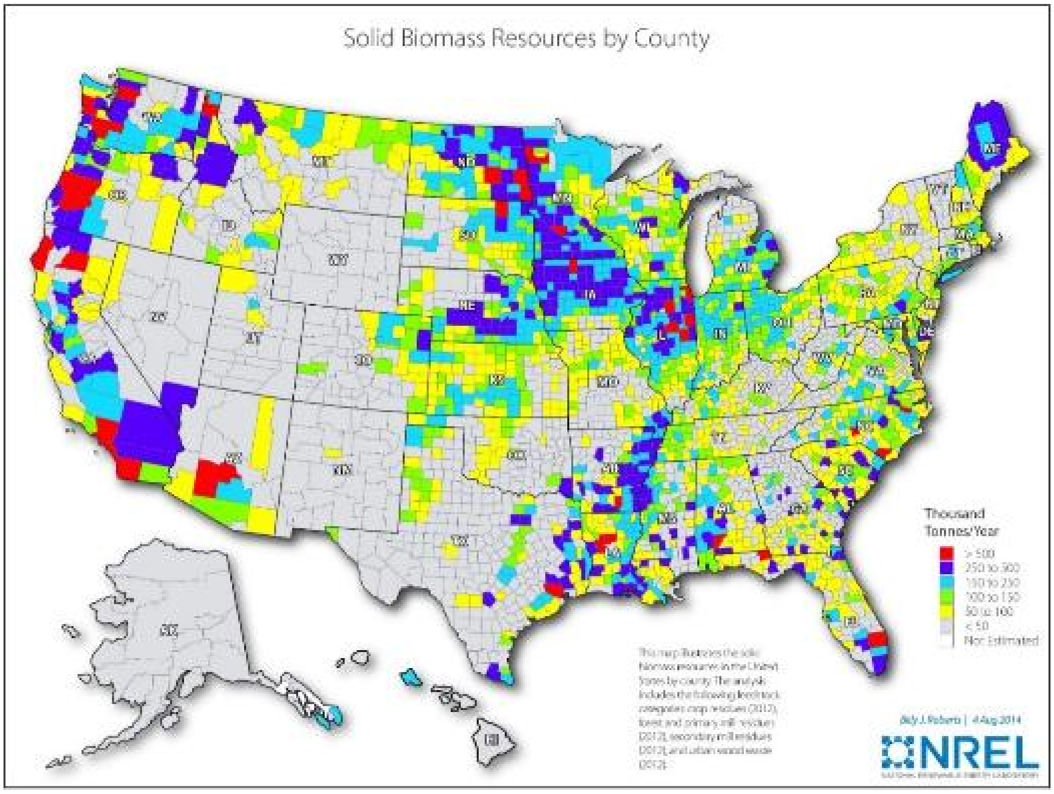
Geothermal fluids are typically high in dissolved minerals and metals, and ongoing water quality monitoring of surface water and groundwater would be required. The location of potential geothermal resources in environmentally sensitive areas has also been a barrier to siting geothermal power facilities in Oregon (Oregon Department of Energy [ODOE] Undated).

Financial Considerations

Typical costs for geothermal electric power plants are extremely variable, and site-specific conditions exert much more influence over power production costs than with other energy sources. The recommended capital development cost for conventional and enhanced geothermal systems (EGS) installations is $5,900/kW and $10,000/kW, respectively (WECC 2014). These development costs do not include exploration or transmission or interconnection, environmental permitting, or land costs. The LCOE is estimated at 4.56 ¢/kWh for conventional systems and 12.61 ¢/kWh for EGS systems.

4.2.5 Biofuels

The Klamath Basin has high potential for biofuel power development. The area’s biomass resource was estimated at 150 to 500 thousand tonnes per year, equivalent to 165 to 551 thousand tons per year, as illustrated in Figure 4-5. The KBRA specifically calls for the management entity to evaluate the potential for development of a biomass energy project (Section 17.7.2.B) with the Klamath Tribes. Therefore, any biofuel power generation facility would likely be located in Oregon on Klamath Tribal Lands and would be ideally located to reduce interconnection costs.



Source: NREL 2014

Figure 4-5. United States Biomass Resources by County

Benefits

An environmental benefit of biofuel power development is that biofuels do not create CO_2 emissions because the CO_2 that is released into the atmosphere is captured in the growth process of creating new biofuel, thus creating a renewable resource. Harvesting biomass could lead to forestry management practices that reduce fire hazard through reduced fuel and greater surface runoff as a result of less vegetative retention. A program focused on juniper harvest could improve the Basin's water supply by reducing evapotranspiration.

Energy developed through biofuel development would be sold to PacifiCorp through a PPA, pursuant to PURPA as a Qualifying Facility. Biofuel power development in the Basin could also provide social benefits with tangible economic value, such as jobs and economic development for Klamath Tribe members.

Constraints

The constraints associated with biofuels stem from two main factors. First, living things are often expensive to care for, feed, house, and harvest. Second, unlike conventional fossil fuels where the original source of carbon has undergone substantial metamorphosis, biofuels contain much more water and other compounds, pound for pound. As a result, they are a less efficient fuel source (Stubblefield 2015). As with other power generation development, siting the power plant near existing transmission or distribution lines is key to reducing transmission costs.

Typically, biofuel power development would require extensive fuel gathering and truck transportation, which increases costs. Depending on the fuel source, this option might require ongoing environmental review and timber harvest planning consistent with National Forest harvesting plans or harvest plans on non-Federal land. How these plans affect this option's lifespan or durability is uncertain.

One potential site-specific constraint facing biomass plants in the Klamath Basin is local opposition and permitting. A proposed biomass plant that was slated to receive $40 million in Federal funding under the American Recovery and Reinvestment Act was halted in June 2013 because of delays in the permitting process, partially caused by local opposition to the project. The delays resulted in the project's inability to meet a firm construction deadline required to qualify for Federal funding under the American Recovery and Reinvestment Act (Creasey 2013).

Financial Considerations

Using conventional combustion technology without cogeneration, the estimated cost to generate electricity from biomass is about double the cost of generating electricity from a new natural gas-fired, combined-cycle power plant (ODOE 2015). However, if the heat byproduct is used for cogeneration of electricity and steam or sold to an industrial user, the overall project cost could be reduced.

The recommended capital development cost for a biofuels plant is $4,300/kW. This development cost does not include fuel, interconnection, environmental permitting, or land costs. The estimated cost for biomass projects requiring harvesting and transportation of fuel (e.g., forest slash) ranges from 1.5 ¢/kWh to 2.9 ¢/kWh (Lazard 2014). The LCOE is estimated at 4.56 ¢/kWh.

4.2.6 Cogeneration

The process of cogeneration captures some, but not all, of the heat produced at thermal power stations that generate heat and uses it either for generating additional electricity or for some other type of space or process heating. The most efficient use of the waste heat depends upon a number of factors including thermodynamics (quantity and temperature of the waste heat) and proximity of the generating plant to the location where the waste heat could be used for process heating. For the purposes of this study, it is assumed that cogeneration would occur via a natural gas-fueled power plant.

Benefits

The primary benefit of cogeneration is the more efficient generation of power. A typical thermal power plant may run with efficiency between 35 and 45 percent, whereas a cogeneration plant may achieve 75 to 95 percent efficiency

(International Energy Agency 2011). Reduction of fuel use and corresponding CO_2 emissions are about 30 percent (Askarov 2010). Regional natural gas transmission lines pass through the Klamath Basin, which reduces the cost associated with creating the infrastructure for providing fuel to the power plant. Additionally, because cogeneration power plants are smaller in scale and more spatially distributed, massive production outages are less probable and shorter transmission lines are required, thus reducing both transmission cost and power loss.

The generated power would be sold to PacifiCorp through a PPA starting at its avoided cost, pursuant to PURPA as a Qualifying Facility.

Constraints

Cogeneration power plants have two basic constraints. First, cogeneration plants are more complex, resulting in higher capital costs and operation and maintenance costs than conventional plants of the same size (Askarov 2010). Second, the power plant location could be limited depending on where the excess heat generated during power production would be used.

In order to qualify as a cogeneration facility, a facility must meet operation, efficiency, and use of energy output standards as defined in 18 CFR §209.205, and must be certified as a Qualifying Facility pursuant to 18 CFR §209.207.

Financial Considerations

The recommended capital development cost for gas cogeneration facilities sized below 5 MW is $3,800/kW, and $1,650/kW for facilities greater than 5 MW. These development costs do not include interconnection, environmental permitting, or land costs. The LCOE is estimated at 9.20 ¢/kWh for facilities below 5 MW and 7.90 ¢/kWh for facilities greater than 5 MW.

KBRA funding is not available for natural gas-powered electrical generation as a non-renewable resource.

4.2.7 Fuel Cells

Fuel cells powered by natural gas could be used to generate electricity to drive individual irrigation pump motors. Several types of fuel cells operate in the range of one watt to greater than one MW, with the load demand playing a part in the type of fuel cell selected. In regard to individual irrigation loads in the Klamath Basin, more than one type of fuel cell may be required.

Natural gas could be supplied through fixed lines or on-site storage tanks. Avista Corporation (Avista), an Oregon natural gas utility whose service area covers part of the Klamath Basin, could provide piped gas to sites in close proximity to supply lines.

PacifiCorp allows natural gas-powered fuel cells to be net metered in Oregon under Schedule 135. In California, PacifiCorp's Schedule NEM-35 allows the net metering of fuel cells using a renewable fuel source, or those using natural gas that meet the definition of "ultra-clean low-emission distributed generation" (CPUC Code 2827.10).

Benefits

Net metering fuel cells could provide Basin irrigators the opportunity to reduce delivered energy costs by directly offsetting the electricity supplied by PacifiCorp with electricity generated by the fuel cells.

Constraints

Fuel cell installations in the Klamath Basin have three major constraints. First is the availability and cost of natural gas. Avista is the only natural gas utility in the Oregon portion of the Klamath Basin, and its service area covers only part of the project area as shown in Figure 4-6. Fixed natural gas service (pipeline delivered services, as opposed to truck deliveries to fill storage tanks) in the California portion of the Klamath Basin is currently not available, and the additional infrastructure and supply costs to obtain this service are unknown.

Source: Northwest Gas Association 2015

Figure 4-6. Natural Gas Systems in Oregon

The second constraint is the fuel source limitations set for fuel cells in California. Currently net metered fuel cells must use renewable fuels or must have a system that meets the definition of "ultra-clean low-emission distributed generation." (CPUC Code 2827.10) This limitation could either eliminate fuel cells as an option in California, or increase the cost due to the technology required to meet the CPUC code.

The last constraint is the size limitations on net metering in both Oregon and California. PacifiCorp's net metering programs limit fuel cell generation to 2,000 kW in Oregon and 1,000 kW in California.

Financial Considerations

The recommended capital development cost for fuel cell installations is $2,500/kW. These development costs do not include the cost of interconnection. The LCOE is estimated at 8.30 ¢/kWh. Compensation from net metered fuel cells would be the same as described for net metered solar PV.

KBRA funding is not available for natural gas-powered electrical generation, as it is a non-renewable resource.

4.3 Load Reduction and Demand Management Options

Load reduction and demand management options focus on programs and funding mechanisms that would enable irrigators to reduce their delivered energy costs by lowering their energy use and demand. These options are described below.

4.3.1 Efficiency and Upgrades

Efficiency and equipment improvements are specifically called for in the KBRA. 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. Improvements to existing equipment would leverage current PacifiCorp and Energy Trust of Oregon (Energy Trust) energy efficiency programs.

More detailed information on the efficiency and energy consumption testing is posted on Reclamation's website at: http://www.usbr.gov/mp/kbao/special_projects/power.html.

Benefits

Efficiency improvements provide an excellent opportunity to reduce energy costs if current equipment is not energy efficient. Strategic equipment replacements could be undertaken to assist in maximizing energy savings at private pumps and select R&T Works facilities. Field testing 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).

Constraints

The main constraint associated with efficiency and equipment improvements is funding. Replacing or upgrading inefficient equipment can be expensive, depending on the size of the equipment.

Financial Considerations

Money, in the form of incentives provided through the Energy Trust, could be leveraged to reduce the program expense. Currently Energy Trust offers PacifiCorp customers in Oregon rebates on irrigation equipment and incentives for pump and irrigation system upgrades, as shown in Table 4-3 below.

Table 4-3. Energy Trust Rebates and Incentives

Type	Incentive[1]
Cash incentives for irrigation equipment	Linear and pivot improvement: • $5 per low-pressure regulator • $4 per rotating-type sprinkler that replaces an impact sprinkler • $3 per sprinkler for new multiple configuration nozzles Wheel and hand-line improvement: • $10 per section of cut and pipe press repair of leaking pipes • $4 per flow controlling type nozzle for impact sprinklers • $2.75 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 cash back on variable frequency drives • Up to 50 percent energy savings for existing pump or linear/pivot system conversions
Scientific irrigation scheduling	• $4.85 per irrigated acre, up to 100 percent of the cost of the service and/or equipment for as many as three years[2]

[1] Values listed in this table are subject to change throughout the year. Visit the Energy Trust website (http://energytrust.org/industrial-and-ag/incentives/agriculture/irrigation-equipment/IrrigationEquipment) for the full list of the most up-to-date offers.

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

4.3.2 Time-of-Use

PacifiCorp currently offers time-of-use programs to its Oregon customers via Schedule 210 – Portfolio Time-of-Use Service and Schedule 215 – Irrigation Time-of-Use Pilot Service. These programs, taken in conjunction with Schedule 41 – Agricultural Pumping Delivery Service, provide customers a credit for energy used during off-peak hours and an additional charge for energy used during on-peak hours.

Ability to Shift Off-Peak

In 2014 Reclamation conducted an informal survey to assess energy use and irrigation practices, including the irrigator's ability to operate off the daily peak (2:00 pm to 6:00 pm June 1 through August 31). Reclamation distributed 350 surveys to Basin irrigators with an 18 percent response rate (63 surveys were returned). The survey concluded that up to 50 percent of irrigators in the Basin could switch to time-of-use programs. The most commonly reported constraints to switching to a time-of-use schedule were the cost of labor and equipment, water delivery schedules, and crop requirements.

Time-of-use opportunities in California are currently not available; however, in February 2015 PacifiCorp filed a request with the CPUC to implement a pilot program similar to Schedule 215. If approved, the California Irrigation Time-of-Use Pilot would offer irrigation customers on Schedule PA-20 in the Tulelake area a credit for energy used during off-peak hours and an additional charge for energy used during on-peak hours.

Schedule 210 is applicable to PacifiCorp's residential and small non-residential customers in Oregon with loads up to 30 kW who receive delivery service under Schedule 41, in conjunction with Schedule 201 – Cost Based Supply Service.

PacifiCorp's Schedule 215 is applicable to Schedule 41 irrigators in Oregon with loads up to 1,000 kW who have voluntarily elected to participate in the pilot program. The California Irrigation Time-of-Use Pilot will be applicable to PacifiCorp's irrigation customers on Schedule PA-20 in the Tulelake area who voluntarily elect to participate. Both the Oregon and California pilot programs limit the number of participating meters. In the future PacifiCorp plans to establish time-of-use schedules available to any irrigator, following the conclusion of the pilots and acceptance from the Oregon Public Utility commission (OPUC) and CPUC.

Benefits

Time-of-use metering is the only option that enables an irrigator to lower their received energy rate. Schedule 210 offers the customer a potential reduction in overall energy rates, as it credits power used during off-peak hours. Under this schedule, customers on Schedule 41 could receive a 1.231 ¢/kWh credit for all energy used during the off-peak period.

Schedule 215 and the proposed California Irrigation Time-of-Use Pilot offer customers serviced under Schedule 41 a credit of 3.161 ¢/kWh and 4.254 ¢/kWh, respectively, for all energy used during off-peak hours. On-peak hours are Monday through Friday 2:00 pm to 6:00 pm from June 1 through August 31.

Constraints

Customers using energy during on-peak hours have the potential to experience higher power costs than they previously received due to the additional charges applied for on-peak energy used under time-of-use schedules. Schedule 210 charges customers an additional 8.004 ¢/kWh for on-peak energy used in the summer and 3.737 ¢/kWh in the winter. Schedule 215 charges customers an additional 17.951 ¢/kWh for energy used during on-peak hours. The proposed California Irrigation Time-of-Use Pilot charges customers an additional 30.022 ¢/kWh for all energy used during on-peak hours. Customers serviced under Schedule 215 and the proposed California pilot are also limited to no more than three meters. For customers to reduce power costs through time-of-use programs, they must be able to modify their irrigation practices to shift power use from on-peak to off-peak hours.

Large-scale time-of-use programs could disrupt water deliveries in KID and Tulelake Irrigation District (TID) to an unknown degree. The future rates of the post pilot time-of-use programs in Oregon and California are uncertain.

Financial Considerations

Neither Energy Trust nor PacifiCorp offer financial incentives or rebates for time-of-use programs. Costs for resizing pumps, installing additional irrigation equipment, and storage can be highly variable from farm to farm.

4.3.3 Irrigation Load Control

PacifiCorp currently offers irrigation load control programs in its Idaho and Utah service territories. Similar programs could be implemented by PacifiCorp in Oregon and California following OPUC and CPUC approval. Currently the irrigation load control programs in Utah and Idaho provide participants with annual compensation for unused power during designated shut-down periods in dollars per kW. Notification is sent to participants prior to shut-down periods, allowing participants to opt out of a given shut-down period.

Benefits

An irrigation load control program implemented in Oregon and California by PacifiCorp could provide Klamath Basin irrigators annual compensation from $19/kW to $23/kW per year per pump for all unused power during designated shut-down periods. Average annual payment is projected to be $1,475 to $2,025. The program is voluntary and allows participants to opt out of any shut-down period. The load control programs in PacifiCorp’s other service areas are available to loads greater than 50 kW, with higher rates offered for loads over 100 kW.

Constraints

PacifiCorp does not currently offer load control programs in Oregon or California; therefore implementation, rates, and the number of Basin irrigators who could participate are uncertain. The programs would also require new meters that allow electricity to be shut off remotely during shut-down periods.

Implementation of a large-scale irrigation load control program in Oregon and California could disrupt water deliveries in KID and TID to an unknown degree.

Financial Considerations

Neither Energy Trust nor PacifiCorp offer financial incentives or rebates for irrigation load control programs.

4.3.4 Federal Power

Power from the Federal Columbia River Power System could be supplied to select Oregon On-Project and Off-Project irrigators by Bonneville Power Administration (BPA).

Benefits

Select irrigation loads in Oregon could receive lower energy rates from BPA.

Constraints

BPA requires that all new customers purchase a new meter and pay a monthly charge. As a result, the Federal Power Workgroup estimated that only 50 percent of the Oregon On- and Off-Project loads would experience lower rates (a maximum 10 percent reduction). In addition, PacifiCorp would charge customers leaving its system to join BPA's system an exit fee, which would reduce the ability to lower overall rates. This exit fee is currently under development by PacifiCorp and the OPUC.

The Western Area Power Administration does not have any available power to serve California loads.

4.3.5 Pump Conversion to Natural Gas

Irrigation pump conversions to natural gas could occur on select irrigation properties in Oregon and California. Natural gas could be supplied through fixed lines or on-site storage tanks. Avista, an Oregon natural gas utility whose service area covers part of the Klamath Basin, could provide piped gas to sites in close proximity to supply lines. On-site storage tanks would be required for all other sites.

Benefits

In some circumstances, natural gas engines are less expensive to operate and allow an operator to vary the motor speed and pump output based on the specific irrigation condition. Natural gas engines also allow irrigation systems to operate 24 hours per day with no regard for the time of use.

Constraints

Three major constraints are associated with converting irrigation pumps to run on natural gas in the Klamath Basin. First is the availability and cost of natural gas. Avista is the only natural gas utility in the Oregon portion of the Klamath Basin, and its service area covers only part of the On- and Off-Project area, primarily the municipal areas. There is currently no fixed natural gas service in the California portion of the Klamath Basin, and the additional infrastructure and supply costs to provide this service, though unknown, are expected to be high.

The second constraint is the durability of internal combustion engines compared to electric motors. In general, natural gas-powered internal combustion engines are thought to be less durable and require more repair, maintenance, and service than electric motors. The useful life of natural gas engines is typically two-thirds the life of electric motors or less, and engine power loss due to engine wear during the useful life must be considered in initial engine sizing.

The last constraint is this option's inability to equitably distribute benefits to irrigators. Benefits would be highly variable, as the cost of conversion at each site is dependent upon gas service availability and equipment sizing.

Financial Considerations
Capital costs for pumps with internal combustion engine drives are several times the cost of an equivalent electric motor and pump and they are available from significantly fewer manufacturers. Natural gas engines typically have higher operation and maintenance costs than electric motors on a dollar per acre basis, although costs vary greatly and are site-dependent. However, the cost of internal combustion engines becomes more competitive compared to electrical motors as motor size and pumping increase, because fuel efficiency increases with horsepower.

KBRA funding is not available for natural gas used to run irrigation pumps.

4.4 Other Energy Cost Reduction Options

4.4.1 Out-of-Basin Investment in Renewables
Investment in renewable energy outside of the Klamath Basin can be done in several ways, including investment in renewable energy mutual funds, exchange traded funds, yieldcos, or a partnership with a developer of renewable power.

Benefits
An investment in renewable energy outside the Basin would provide a yearly cash dividend that would be returned as a credit on the irrigator's bill.

Constraints
The two main constraints associated with investment outside the Basin are risk and public perception. Any investment would require close evaluation of the finances, the partnership, and its future durability. 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.

Financial Considerations
Investment in renewable energy through an investment mechanism (yieldco or exchange traded fund) is projected to provide an annual return of four percent on the capital investment.

4.4.2 On-Project Plan
The KBRA requires KWAPA to develop the On-Project Plan (OPP) to address the water supply and demand balance for On-Project irrigators within the On-Project Plan Area as a result of the KBRA's changes to water supply in the Klamath Basin. While the OPP Summary Report and the OPP's Environmental Impact Statement/ Environmental Impact Report (currently under development) address water supply issues, the OPP options and alternatives were not formulated specifically to reduce energy or power costs for On-Project irrigators. The CAPP evaluation considers the OPP options that are components of the proposed program (as identified in Technical Memorandum 7, *Proposed On-Project Plan Program and Implementation and Administration,* of the OPP Summary Report, KWAPA 2014b). Some of the OPP options considered cover:

- Water conservation and efficiency
- Groundwater
- Additional surface water availability
- Demand management options

Benefits
Some of the OPP options have the potential to reduce overall power costs for On-Project irrigators. For example, recirculation of water at Tulelake Sump 1A would eliminate pumping at D-plant from March until August, effectively reducing power costs. Relocating groundwater wells to more advantageous groundwater production areas with a higher groundwater table would also reduce pumping costs. Demand management options such as land idling also have the potential to reduce overall energy costs as they would require either full year or partial year reductions in irrigation.

Constraints
Benefits are restricted to a subset of On-Project irrigators and exclude all Off-Project irrigators. Some OPP options have no effect on power or have the potential to increase power consumption. For example, rerouting Klamath Straits Drain (KSD) Flow to Lower Klamath National Wildlife Refuge would install new pumps to lift water from KSD to the 6A canal. Water delivered to the refuge would have otherwise been pumped to the KSD. The net energy consumption with this reoperation is unknown. Many of the groundwater options could increase groundwater pumping, increasing power costs.

Financial Considerations
KBRA funding could be used to fund OPP options that also reduce energy usage.

Technical Workgroup Meeting #3

TWG Meeting #3 was held on February 20, 2015 in the Klamath Water and Power Agency (KWAPA)/Klamath Water Users Association conference room in Klamath Falls, Oregon. A webinar was held simultaneously for those who could not attend in person.

Purpose

The purpose of this meeting was to review the regulations in Oregon and California that affect power development, present load reduction and demand management options, present potential power development options, identify additional options, and review a set of screening criteria for the evaluation of options and alternatives.

Major Outcomes and Decisions

The TWG suggested that additional options that invest in renewable power development outside the Basin and on-farm fuel cells powered by natural gas be investigated, as well as power savings-related aspects of the On-Project Plan. It was also suggested that geothermal and wind development in the Basin be dropped from further analysis. The TWG suggested that the screening criteria for option evaluations include durability and administration.

PacifiCorp indicated that the California net metering program is not near its cap. The incentive money for the program is separate from the net metering program and will run out in April 2015, but PacifiCorp has submitted a docket to extend the incentive period another year. PacifiCorp further stated that they would support reasonable measures to distribute power, like community aggregation, but pointed out that the California Public Utilities Commission (CPUC) and Oregon Public Utility Commission (OPUC) are responsible for changes to policy.

Chapter 5 Options Screening

This chapter provides the screening criteria and performance measures developed to evaluate Comprehensive Agricultural Power Plan (CAPP) options. The set of screening criteria were used to screen the energy rate and cost reduction options identified during CAPP Technical Workgroup (TWG) meeting three (TWG-3). This information was developed for presentation at the CAPP TWG-4 with the intent of identifying a set of preferred options for further engineering and economic analysis and combination into comprehensive alternatives.

5.1 Screening Criteria and Performance Measures

Screening criteria and performance measures are used to differentiate the characteristics of the CAPP options and alternatives. The criteria define what an option or alternative is attempting to achieve. The performance measures are used to indicate to what degree a specific criterion is being achieved. The metrics for the criteria may be quantitative or qualitative.

5.1.1 Consistency with the Klamath Basin Restoration Agreement

Section 17.7.2 of the Klamath Basin Restoration Agreement (KBRA) specifies that investments will be made in renewable resource generation or energy efficiency measures and will be identified in the Financial and Engineering Plan for the CAPP. Section 17.7.3 includes one funding criterion that "the projects are for renewable resources under applicable law of the state where the project is located." KBRA funding for non-renewable power development may require changing the agreement to the satisfaction of all signatory parties.

Table 5-1 presents the metrics for how an option is consistent with the current KBRA.

Table 5-1. Criterion 1: Consistency with the KBRA

Measure	Description
Yes	Consistent with the KBRA
No	Inconsistent with the KBRA

5.1.2 Consistency with Regulations and Policies

The states of Oregon and California have established their own regulations and policies for the generation, transmission, and distribution (GTD) of power. Table 5-2 presents the metrics for how an option for GTD is consistent with all existing Oregon Public Utility Commission (OPUC) and California Public Utilities Commission (CPUC) regulations and policies, including Federal Energy Regulatory Commission (FERC) policies administered by the states.

Table 5-2. Criterion 2: Consistency with Regulations and Polices

Measure	Description
Excellent	Consistent with all regulations and policies in both states
Good	Consistent with most regulations and policies in both states
Fair/Tolerable	Inconsistent with regulations and policies in one state
Poor	Inconsistent with regulations and policies in both states

5.1.3 Access to Benefits

Three groups of irrigators could receive benefits under the KBRA: 1) Oregon On-Project, 2) Oregon Off-Project, and 3) California On-Project. These groups either have different operational practices or are subject to differing state regulatory frameworks. Table 5-3 presents the metrics for how consistently a potential option could be implemented across the three groups. Limited access to an option may not disqualify it from further consideration if it can be paired with another option with complementary access, yielding a package of options with good access overall.

Table 5-3. Criterion 3: Access to Benefits

Measure	Description
Excellent	Accessible to all individuals in all groups
Good	Accessible to most individuals in all three groups
Fair/Tolerable	Accessible to most individuals in at least two groups
Poor	Accessible to only one group or benefits are limited to select individuals in two or more groups

As an example, private pump efficiency improvements could be undertaken consistently among the three groups although the individual power-saving benefit would be different for each private pump owner. The equitability of the distribution of benefits is addressed economically in Criterion 4.

5.1.4 Distribution of Benefits

It is important that benefits provided by the KBRA are equitably distributed among all irrigators, subject to the limitations on eligibility set forth in Section 17.3 of the KBRA. This criterion is different from Criterion 3 in that it looks at the end benefit, not simply whether the program is accessible to all Basin irrigators. Benefits can be provided in different forms including a direct offset of energy rates through net metered installations, a rate reduction, an annual distribution or dividend, or a payment for equipment upgrades. Table 5-4 presents the metrics for ability to provide equal benefits to irrigators, without assumptions about the precise form of such benefits.

Table 5-4. Criterion 4: Equitable Distribution of Benefits

Measure	Description
Excellent	Benefits distributed easily on pro-rata energy use basis
Good	Benefits distributed equally to most irrigators
Fair/Tolerable	Benefits distributed to most, unequally
Poor	Benefits distributed to only a few, unequally

5.1.5 Administrative Intensity

Each option will have different administrative requirements for the Management Entity to operate and maintain the option over its lifecycle and to manage and distribute any associated benefits. Administrative functions would likely be the responsibility of Klamath Water and Power Authority (KWAPA) or the Bureau of Reclamation (Reclamation). Table 5-5 presents the metrics for the administrative effort required by the Management Entity at option initiation and over the lifetime of the option.

Table 5-5. Criterion 5: Administrative Intensity

Measure	Description
Excellent	Requires a one-time initial low level effort
Good	Requires a one-time moderate initial effort or long-term low level effort
Fair/Tolerable	Requires a one-time high initial effort and easy or moderate long-term administrative effort
Poor	Requires a one-time high initial effort and moderate to high long-term effort

5.1.6 Durability

The durability (life) of an option is a function of the technology employed, current regulations, and future policies. Technologies have differing operational lives; for example, internal combustion engines have shorter lives than electrical motors. Future policies are uncertain, but could relate to new energy models that integrate distributed energy and demand response to reduce reliance on centralized fossil resources.

Table 5-6 presents the metrics for the potential durability of an option based on the technology and projections of how regulations might change in the future with new policy development.

Table 5-6. Criterion 6: Durability

Measure	Description
Excellent	High life certainty beyond 20 years
Good	Moderate life certainty of 15 to 20 years
Fair/Tolerable	Moderate life certainty of 10 to 14 years
Poor	Life certainty under 10 years

5.1.7 Levelized Cost of Energy

The levelized cost of energy (LCOE) is a calculated cost of generating electricity in cents per kilowatt-hour (¢/kWh) at the point of connection to the electrical grid. The LCOE is a net present value calculation for the expected life of the project and is therefore a "levelized" cost for the project life. The LCOE calculation includes initial capital cost, annual operations and maintenance (O&M) costs, cost of money (discount rate), and cost of fuel. The LCOE calculation also assumes a $40 million initial capital investment funded by the KBRA for all KBRA-consistent options. This LCOE allows an equal comparison of power generation options but does not include site-specific option development costs including utility interconnection, land, and environmental compliance. Table 5-7 presents the metrics for the LCOE evaluation.

Table 5-7. Criterion 7: LCOE

Measure	Description (¢/kWh)
Excellent	LCOE < 2
Good	2 ≤ LCOE < 5
Fair/Tolerable	5 ≤ LCOE < 8
Poor	LCOE ≥ 8

5.1.8 Power Rates/ Costs

Each option will have an ability to reduce power costs for an individual irrigator through lowering rates or lowering the overall power cost by affecting another component of the energy use equation. For example, energy rates can be lowered through time-of-use metering and power costs can be lowered by providing a dividend to an irrigator. Table 5-8 presents the metrics for an option's ability to lower power costs by calculating a potential rate or cost reduction.

Table 5-8. Criterion 8: Power Rates/ Costs

Measure	Description
Excellent	Rate/cost reduction of 40% or greater
Good	Rate/cost reduction of 20-39%
Fair/Tolerable	Rate/cost reduction of 6-19%
Poor	Rate/cost reduction of less than 6%

Rate reduction percentages for the CAPP options were calculated for Oregon and California, where possible. Where an option resulted in the generation of revenue, the revenue is distributed equally across all Schedule 41 and PA-20 users through a direct rate credit on the bill. The CAPP Regulatory Framework Report (summarized in Chapter 3) provided the annual baseline energy used in these calculations. Rate reduction percentages for each state are determined by subtracting the annual net revenue or value of offset energy from the current energy cost, dividing it by the annual energy demand, and then finding the percent difference between this new rate and the current energy rate.

For example, presume that a $40 million investment is used to build a 15,400-kW utility-scale solar project capable of producing approximately 40.4 million kWh annually. Irrigators would still purchase all energy needs through PacifiCorp under their scheduled rates, which for Oregon Schedule 41 users is 9.674 ¢/kWh. In Oregon, On-Project irrigators demand 47 megawatts (MW) of power annually and Off-Project irrigators demand 30 MW annually. Oregon irrigators' combined annual energy use is 96 million kWh. Multiplying the energy use by the energy rate results in a total cost of $9.3 million. Now presume that the operation and maintenance of the solar project costs $27/kW, or $416,000. Since the Oregon irrigators account for 73 percent of the Basin power demand, their share of the O&M costs would be about $304,000. If the energy from the solar project is sold at PacifiCorp's average avoided cost of 3.4¢/kWh, the Oregon irrigators' share of those sales would be $1,003,000 ($.034/kWh * 40,400,000 kWh * 0.73). Therefore, the net cost of electricity for the Oregon irrigators is $9.3 million plus $304,000 less $1,003,000, or $8,601,000. Dividing this net cost by the total Oregon irrigator's electricity use of 96 million kWh results in an average cost of 8.96¢/kWh. The percent difference between this rate and the Schedule 41 rate of 9.674¢/kWh is 7 percent [(9.674-8.96)/9.674].

5.1.9 Environmental Impact

Each option will have some effect on the local environment requiring initial, and potentially extended, environmental review. Some options could have long-term impacts on the environment, including climate change impacts. Table 5-9 presents the metrics for the potential impact of each option on the environment.

Table 5-9. Criterion 9: Environmental Impact

Measure	Description
Excellent	No effect to environmental resources
Good	Minor footprint effects that might require mitigation
Fair/Tolerable	Footprint or long-term effects that require mitigation
Poor	Footprint or long-term effects with un-mitigatable effects requiring an environmental impact statement (EIS)

5.2 Option Ratings

The options were evaluated using the screening criteria and performance measures described in Section 5.1. The results are summarized below. General assumptions for the analysis included the following:

- Public Utility Regulatory Policies Act (PURPA) Qualified Facilities would sell power at the avoided cost of 3.4 ¢/kWh
- Estimated costs and revenues do not include land purchase, permitting, or interconnection

Additionally, the Klamath Basin baseline energy assumptions are provided in Table 4-1.

5.2.1 Power Development Options

This subsection presents the preliminary screening results for the power development options evaluated against the criteria and measures.

5.2.1.1 Natural Gas Development

Power generation facilities using natural gas would be developed consistent with PURPA, with energy sold to PacifiCorp at its avoided cost. For all PURPA power development options, any economic benefits would be distributed to irrigators as a kWh pro-rata rate credit and would apply equally to all Schedule 41 and PA-20 irrigators, affecting approximately 118 million kWh annually. Economic benefit distribution could occur through PacifiCorp as a kWh rate credit on the bill or directly through the Management Entity. A natural gas facility could be located in Oregon or California, placed at an ideal location to reduce interconnection costs, and optimized to the existing gas transmission facilities.

Key assumptions for natural gas development include the following:

- Natural gas power generation is not a renewable resource and is inconsistent with the KBRA.
- The LCOE for natural gas development assumes a 10.5 MW combined cycle gas turbine costing $40 million.

- The analysis assumes that KBRA funding would not be available for this technology, as reflected in its high LCOE costs, and would require repayment of capital over 25 years at a rate of 3 percent.

- Estimated fuel costs using 2014 natural gas costs and projections are 3.1 ¢/kWh.

- O&M costs would be $10/kW, for a total of $105,000 annually.

- Natural gas development would require a high level of administrative intensity. The project would require construction, O&M, and staffing costs.

- Natural gas generation will have long-term greenhouse gas impacts that could require costly environmental mitigation.

Based on the stated assumptions, natural gas-generated electricity would be sold at a $2 million loss to PacifiCorp. Table 5-10 presents the performance of natural gas development evaluated against the screening criteria.

Table 5-10. Natural Gas Development Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Natural Gas Development > 5 MW	🟥	🟩	🟩	🟩	⬛	🟩	⬛ 7.90	🟥 -16	🟥 -19	🟥
Natural Gas Development < 5 MW	🟥	🟩	🟩	🟩	⬛	🟩	🟥 9.20	🟥 -17	🟥 -21	🟥

Legend: 🟩: Excellent/Yes 🟦: Good ⬛: Fair/Tolerable 🟥: Poor/No

5.2.1.2 Utility-Scale Solar

Utility-scale solar would be developed consistent with PURPA, with energy sold to PacifiCorp at its avoided cost. Economic benefits from utility-scale solar would be distributed to all Schedule 41 and PA-20 irrigators annually. This distribution could occur through PacifiCorp as a kWh rate credit on the bill or directly through the Management Entity. The facility could be located in Oregon or California and placed at an ideal location to reduce interconnection costs.

Key assumptions on utility-scale solar development include the following:

- Assuming an initial $40 million KBRA-funded investment, the option would develop a 15,400-kW facility ($2,600/kW) capable of producing 40.4 million kWh annually at a capacity factor of 0.3.

- O&M costs would be $27/kW, for a total of $415,000 annually.

- Power would be sold to PacifiCorp at the average avoided cost rate of 3.4 ¢/kWh.

- Utility-scale solar is a proven technology, has good durability with a 25-year life or more, and would require limited O&M costs compared to other power generation alternatives.

- Utility-scale solar uses single axis tracking, which provides greater efficiency and a higher capacity factor than small-scale solar.

- The facility could be placed at a single location or at distributed sites. The facility would cover an area of approximately 110 to 140 acres, assuming 7 to 9 acres are required per 1,000 kW, and mitigation would be required for the environmental impacts.

- Economic benefits would be distributed by PacifiCorp as a kWh rate credit on the bill.

Based on the stated assumptions, this option would yield approximately $959,000 in annual net revenue. This would result in an annual rate reduction of approximately seven percent in Oregon and nine percent in California. Table 5-11 presents the performance of utility-scale solar evaluated against the screening criteria.

Table 5-11. Utility-Scale Solar Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	Power Rates/Costs % Reduced CA	Env. Impact
Utility Scale Solar	🟩	🟩	🟩	🟩	🟦	🟩	🟩 1.89	⬛ 7	⬛ 9	🟦

Legend: 🟩: Excellent/Yes 🟦: Good ⬛: Fair/Tolerable 🟥: Poor/No

5.2.1.3 Progressive Utility-Scale Solar

Progressive utility-scale solar development is defined for the purpose of this study as utility-scale solar that allows for community meter aggregation or virtual metering. KBRA Section 17.4.7, Net Metering, states that aggregation of loads and other “arrangements” are anticipated and that the parties agree to cooperate to develop net metering arrangements with PacifiCorp and to “support any Regulatory Approvals that may be required.” Current policies do not allow virtual metering or aggregation in Oregon and it is not required of PacifiCorp in California. If current policies in Oregon and California are modified, progressive utility-scale solar could offer a good-to-excellent ability to distribute benefits to On- and Off-Project irrigators in Oregon and California, with good-to-excellent ability to lower rates or overall power costs. Administrative efforts to alter state policies, track energy generation and use, and distribute benefits are anticipated to be high.

Key assumptions on progressive utility-scale solar development include the following:

- With an initial $40 million KBRA-funded investment, the option would develop 11,760 kW ($3,400/kW) over multiple facilities capable of producing/ offsetting about 28.9 million kWh annually at a capacity factor of 0.28.
- O&M costs would be $28/kW, for a total of $330,000 annually.
- All generation would be virtually metered to Oregon and California loads.
- The CAPP Management Entity would take the lead along with PacifiCorp to change the policies to allow meter aggregation or virtual metering in Oregon and California. The ability to successfully accomplish this policy change in both states is unknown.
- The CAPP Management Entity would track energy generation and use and distribute benefits. If PacifiCorp managed these actions the administrative requirements would be reduced.
- The ability to distribute benefits is hypothetically based on the Local Government Renewable Energy Self-Generation Bill Credit Transfer Program in California, where a generator of renewable energy can transfer excess bill credits to 50 other benefitting accounts. With a total of 2,500 irrigation meter accounts, 50 different facilities would be developed.
- The facilities would be placed at multiple sites covering a total area of approximately 80 to 110 acres, assuming 7 to 9 acres are required per 1,000 kW of photovoltaic solar. Environmental mitigation may be required, depending on project locations.

Based on the stated assumptions, this option has the ability to offset about $2.7 million annually, providing an annual rate reduction of approximately 19 percent in Oregon and 33 percent in California. Table 5-12 presents the performance of progressive utility-scale solar evaluated against the screening criteria.

Table 5-12. Progressive Utility-Scale Solar Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Progressive Utility-Scale Solar	■ (Excellent/Yes)	■ (Poor/No)	■ (Excellent/Yes)	■ (Excellent/Yes)	■ (Fair/Tolerable)	■ (Good)	■ (Excellent/Yes) 1.92	■ (Fair/Tolerable) 19	■ (Good) 33	■ (Good)

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.1.4 Biofuels

Biofuel power generation would be developed consistent with PURPA, with energy sold to PacifiCorp at its avoided cost. Economic benefits from biofuels would be distributed to irrigators annually through a PacifiCorp rate credit on the bill or directly through the Management Entity. This facility would likely be located in Oregon on Klamath Tribal lands and placed at an ideal location to reduce interconnection costs.

Key assumptions on biofuel power development include the following:

- Assuming an initial $40 million KBRA-funded investment, the option would develop a 9,300-kW facility ($4,300/kW) capable of producing 67.6 million kWh annually at a capacity factor of 0.83.
- O&M costs would be $120/kW, for a total of $1.1 million annually.
- Estimated fuel costs are $0.029/kW.
- Power would be sold to PacifiCorp at the average avoided cost rate of 3.4 ¢/kWh.
- The benefit to the Klamath Tribes from the project is not defined. It is assumed that the Tribes would take a percentage of the annual revenue, which would decrease the option's ability to distribute benefits to irrigators.
- Biofuel technology is a proven technology that has good durability with a 25-year or greater life.
- Biofuels would require extensive fuel gathering and truck transportation.
- Depending on the fuel source, this option might require ongoing environmental review and timber harvest planning consistent with National Forest harvesting plans or harvest plans on non-Federal land. How these plans affect the option's durability is uncertain.

- If the biofuels program were focused on juniper harvest, this option might have the added benefit of improving Basin water supply.

Given the stated assumptions, biofuel-generated electricity would be sold at a loss of $3 million. Table 5-13 presents the performance of biofuels evaluated against the screening criteria.

Table 5-13. Biofuel Development Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR		Env. Impact
								OR	CA	
Biofuels	■	■	■	■	■	■	■ 4.56	■ -24	■ -29	■

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.1.5 Low-Head Hydropower

Low-head hydropower (hydro) would be developed consistent with PURPA, with energy sold to PacifiCorp at its avoided cost. Economic benefits from low-head hydro would be distributed to irrigators annually through a PacifiCorp rate credit or could accrue to an irrigation district. Current low-head hydro locations are in Oregon at PacifiCorp's Keno Dam, Eastside and Westside Powerhouses, or Klamath Project irrigation canals.

Key assumptions on low-head hydro development include the following:

- With an initial $40 million KBRA-funded investment, the option could develop low-head hydro facilities up to a maximum of 10,000 kW at $4,000/kW, capable of producing 46 million kWh annually at a capacity factor of 0.53.

- O&M costs would be $30/kW, for a total of $300,000 annually.

- Power would be sold to PacifiCorp at the average avoided cost rate of 3.4 ¢/kWh.

- Low-head hydro placed in the irrigation canals would likely be controlled by an irrigation district similar to the operations of the Klamath Irrigation District (KID) low-head plant on Canal C, with the benefits accruing to KID.

- Keno, and likely Eastside and Westside, development would require consultation with United States Fish and Wildlife Service and National Marine Wildlife Service over Endangered Species Act-listed suckers and

Coho salmon. A facility under 10 MW at an existing dam, or under 40 MW at an existing irrigation canal, can seek an exemption to FERC licensing.

- Future operations and durability could be affected by changes to the listed species biological opinions and the potential for anadromous fish passage with dam removal.

Given the stated assumptions, this option would yield up to approximately $1.3 million in annual gross revenue. This would result in an annual rate reduction of approximately 10 percent in Oregon and 12 percent in California. Table 5-14 presents the performance of low-head hydro evaluated against the screening criteria.

Table 5-14. Low-Head Hydro Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	Power Rates/Costs % Reduced CA	Env. Impact
Low-Head Hydro	■ (Excellent/Yes)	■ (Excellent/Yes)	■ (Good)	■ (Fair/Tolerable)	■ (Fair/Tolerable)	■ (Excellent/Yes)	■ (Excellent/Yes) 1.98	■ (Fair/Tolerable) 10	■ (Fair/Tolerable) 12	■ (Fair/Tolerable)

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.1.6 Small-Scale, Net Metered Solar

Small-scale, net metered solar would be developed consistent with current policies and regulations in Oregon and California. Small solar installations would be installed on select irrigation pumps in both states. Economic benefits from small-scale, net metered solar would accrue to the net meter owner. Solar installations that generate more energy than used over a 12-month period would be compensated in California, but not in Oregon. Net meter solar is “behind the meter” and has an excellent ability to lower rates by completely offsetting the PacifiCorp rate.

Key assumptions on small-scale, net metered solar development include the following:

- With an initial $40 million KBRA-funded investment, the option would develop multiple installations at $3,800/kW with a combined capacity of 10,530 kW capable of producing/ offsetting about 21 million kWh annually at a capacity factor of 0.23.

- O&M costs would be the responsibility of the net meter owner, and are estimated at $30/kWh.

- The value of this power is approximately $2.2 million annually.

- Economic benefits from small-scale, net metered solar would be difficult to distribute equally to irrigators, as benefits directly offset energy charges on a single power bill and the installation of net-metered solar for every irrigator is not possible. Installations on larger Reclamation or irrigation district pumps could provide a better distribution of benefits to the On-Project irrigators.

- Policies are inconsistent between the states, generally favoring Oregon development over California.

Given the stated assumptions and for comparison to other options, if the projected power cost savings were distributed equally to all Schedule 41 and PA-20 users, it would result in an annual rate reduction of approximately 16 percent in Oregon and 26 percent in California, excluding O&M costs. Table 5-15 presents the performance of small-scale, net metered solar evaluated against the screening criteria.

Table 5-15. Small-Scale, Net Metered Solar Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Small Scale Solar (Net Metered)	■ Excellent/Yes	■ Good	■ Good	■ Fair/Tolerable	■ Excellent/Yes	■ Good	■ Excellent/Yes 1.98	■ Fair/Tolerable 16	■ Good 26	■ Excellent/Yes

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.1.7 Fuel Cells

Natural gas-powered fuel cells would be used to generate electricity to drive an individual irrigation pump motor. Many different types of fuel cells operate in the range of one watt to greater than a megawatt, with the load demand playing a part in the type of fuel cell selected. Natural gas could be supplied through fixed lines or on-site storage tanks. Avista, an Oregon natural gas utility whose service area covers part of the Klamath Basin, could provide piped gas to sites that are close to a supply line. All other sites would need to rely on on-site storage. No natural gas utility service is available in the On-Project area of California; therefore, this region would need to rely on on-site storage. Oregon allows the net metering of fuel cells powered by natural gas up to 2,000 kW. California allows net metered fuel cells up to 1,000 kW, but restricts them to those with a renewable fuel source or those whose natural gas system meets the definition of “ultra-clean and low-emission distributed generation” (CPUC Code 2827.10).

Key assumptions on fuel cell usage include the following:

- Natural gas fuel cell power generation is not a renewable resource and is inconsistent with the KBRA.

- The LCOE for fuel cell development assumes an investment of $40 million over multiple installations at $2,500/kW with a combined capacity of 16,000 kW.

- The analysis assumes that KBRA funding would not be available for this technology and it would require repayment of capital over 25 years at a rate of 3 percent.

- Estimated fuel costs are 3 ¢/kWh, or 0.879 cents per therm.

- Fuel cells are net metered, but there is no advantage to over-generate beyond a pump's annual kWh demand because the power is donated to PacifiCorp's low-income program in Oregon and sold at about 4 ¢/kWh in California.

- The net metered fuel cell would be sized to generate the number of kWh annually that would be used over the May to September irrigation season. Based upon the survey of 21 Basin private pumps, the average pump used 49,000 kWh annually (see Appendix C). With a capacity factor of 0.7, the average fuel cell would be sized at approximately 8 kW and would have a capital cost of $20,000 (annual repayment of $1,149 over 25 years, at 3 percent).

- O&M costs would be the responsibility of the net meter owner, and are estimated at $35/kWh.

- A rate reduction was not calculated in California because no fixed gas service exists and the additional infrastructure and supply costs are unknown.

- It is unknown if natural gas fuel cells meet the ultra-clean and low-emission distributed generation standard in California.

- Given the stated assumptions, using fuel cells to generate power to average sized pumps would result in a 33 percent rate reduction in Oregon, excluding O&M costs, where a gas supply is available on-site. Additionally, the access to benefits and the ability to distribute benefits is highly variable and scored as marginal. Each site would require different development requirements, depending upon proximity to a natural gas line or need for storage and the fuel cell size based upon pump load. Table 5-16 presents the performance of net metered fuel cells evaluated against the screening criteria.

Table 5-16. Fuel Cells Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	Power Rates/Costs % Reduced CA	Env. Impact
Fuel Cells	■ (red)	■ (black)	■ (black)	■ (black)	■ (blue)	■ (blue)	■ (black) 8.30	■ (blue) 29	?	■ (blue)

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No; ?: Unknown

5.2.1.8 Geothermal

Geothermal power generation would be developed consistent with PURPA, with energy sold to PacifiCorp at its avoided cost. Economic benefits would be distributed to irrigators as a kWh pro-rata rate credit and would apply equally to all Schedule 41 and PA-20 irrigators. Economic benefit distribution could occur through PacifiCorp as a kWh rate credit on the bill or directly through the Management Entity. A geothermal power plant could be located in Oregon or California, placed at an ideal location with sufficient geothermal resources to reduce interconnection costs.

> **Geothermal Reenters CAPP Evaluation**
>
> Geothermal was removed from the list of power development options during TWG-3 after exhibiting strong negative power cost reduction potential. Prior to TWG-4 it was readmitted, at stakeholder suggestion, following the reported availability of geothermal wells for purchase in the Klamath Basin for the purpose of energy development with the understanding that project costs could be substantially reduced. In May 2015 an investigation into potential geothermal well purchases in the Klamath Basin was undertaken to determine if wells were for sale, their location, and price. The investigation concluded that there are no geothermal wells nor project partnerships currently available.

Key assumptions on geothermal power development include the following:

- Assuming an initial $40 million KBRA-funded investment, the option would develop a 6,780-kW facility ($5,900/kW) capable of producing 50.5 million kWh annually using conventional technology, or a 4,000-kW facility ($10,000/kW) capable of producing 29.8 million kWh annually using enhanced geothermal technology, both at a capacity factor of 0.85.

- For conventional systems, O&M costs would be $120/kW, for a total of $814,000.

- For enhanced systems, O&M costs would be $400/kW, for a total of $1.6 million annually.

- Well field costs used in this analysis were estimated at $500,000.

- Conventional geothermal electricity would be sold to PacifiCorp at the average avoided cost rate.

- Costs do not include exploration or transmission or the cost of interconnection, environmental permitting, or land costs, as geothermal development is extremely site specific.

- Geothermal power generation facilities will likely have multiple environmental effects, and may require ongoing water quality monitoring of surface water and groundwater.

Given the stated assumptions, the conventional option would yield approximately $403,000 in annual net revenue. This would result in an annual rate reduction of approximately three percent in Oregon and four percent in California. The enhanced geothermal electricity would be sold to PacifiCorp at a $1.1 million loss. Table 5-17 presents the performance of geothermal power development evaluated against the screening criteria.

Table 5-17. Geothermal Power Development Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Geothermal - Conventional	🟩	🟩	🟩	🟩	⬛	🟩	🟦 4.56	🟥 3	🟥 4	🟦
Geothermal - Enhanced	🟩	🟩	🟩	🟩	⬛	🟩	🟥 12.61	🟥 -9	🟥 -10	🟦

Legend: 🟩: Excellent/Yes 🟦: Good ⬛: Fair/Tolerable 🟥: Poor/No

5.2.2 Demand Management, Investment, and Alternate Source Development Options

This subsection presents the screening of other options that could be used as tools to lower power costs or rates. Since these options do not develop power, LCOE is not used as a screening criteria. KBRA funding could be used to advance these options as larger basin-wide programs or to provide a monetary incentive for an irrigator to participate in a program.

5.2.2.1 Federal Power

Power from the Federal Columbia River Power System would be supplied to select Oregon On- and Off-Project irrigators by the Bonneville Power Administration (BPA). Economic benefits from Federal power would be distributed to select irrigators in Oregon in the form of lower power rates offered by BPA. To take Federal power, an exit fee from PacifiCorp would be charged, reducing the ability to lower overall power costs. This exit fee is currently under development by PacifiCorp and the OPUC. Each load served by BPA would also require a new BPA meter and monthly charge.

Key assumptions on Federal power use include the following:

- The Federal Power Workgroup estimated that only 50 percent of the Oregon loads would experience lower rates (maximum 10 percent reduction) due to the meter costs.
- The Western Area Power Administration has no available power to serve California loads.
- The CAPP Management Entity would be required to coordinate Federal power contracts, costs, and benefits.

Table 5-18 presents the performance of federal power evaluated against the screening criteria.

Table 5-18. Federal Power Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Federal Power	■ Excellent/Yes	■ Good	■ Poor/No	■ Poor/No	■ Fair/Tolerable	■ Excellent/Yes	■ Fair/Tolerable	■ Poor/No	■ Excellent/Yes

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.2 Time-of-Use

Time-of-use programs would be implemented consistent with current and proposed policies and regulations in Oregon and California. Economic benefits from time-of-use programs would accrue to Oregon's On- and Off-Project irrigators who choose to enter the program and would be in the form of a rate reduction. Irrigator participation in time-of-use is limited by the ability to shift to the off-peak hours during the irrigation season, which can be constrained by equipment, irrigation practices and labor requirements, and water delivery schedules.

Policy changes are required to institute a time-of-use program in California through the CPUC. PacifiCorp has submitted a pilot tariff to the CPUC, which could begin in 2016. PacifiCorp's Tariff 215 program in Oregon is a pilot program with uncertain future rates, conditions (e.g., it limits participation to up to three meters per owner), and longevity. PacifiCorp has stated that it could be two or more years following the pilot's completion before a time-of-use tariff can be approved by the OPUC. KBRA funding could be used to create a loan and/or grant fund to modify on-farm and/or irrigation district level improvements to facilitate time-of-use.

Key assumptions on time-of-use include the following:

- KID and Tulelake Irrigation District (TID) have publicly stated that large-scale time-of-use metering could disrupt water deliveries, requiring yet-to-be identified changes to the water distribution system to accommodate time-of-use.
- With tariffs in Oregon and California (upon OPUC and CPUC approval), all irrigators would have the ability to equally participate in the program. However, because these programs are in the pilot stage, their ultimate definition, ability to participate, and durability are uncertain.
- District level changes needed in the TID, KID, and Klamath Drainage District (KDD) to support a time-of-use program are unknown.
- PacifiCorp’s 215 tariff rates were used to score the option’s ability to lower rates.
- KBRA funding would be used to optimize the water delivery, storage, and irrigation systems to accommodate time-of-use. Energy Trust of Oregon (Energy Trust) and PacifiCorp do not provide monetary incentives for time-of-use.

Table 5-19 presents the performance of time-of-use evaluated against the screening criteria.

Table 5-19. Time-of-Use Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Time-of-Use	■ (Excellent/Yes)	■ (Fair/Tolerable)	■ (Good)	■ (Fair/Tolerable)	■ (Excellent/Yes)	■ (Fair/Tolerable)	■ (Excellent/Yes)	■ (Fair/Tolerable)	■ (Excellent/Yes)

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.3 Irrigation Load Control

Irrigation load control would be implemented by PacifiCorp following policy changes that establish load control programs in Oregon and California. Because these programs are not in place in either state at this time, there are many uncertainties regarding the program’s policies, rates, and durability.

Economic benefits from irrigation load control would be distributed by PacifiCorp to participating irrigators in the form of annual compensation for unused power during designated shut-down periods in dollars per kilowatt-hour. It is unknown how many irrigators could participate in the program and, depending upon the number of potential program participants, irrigation district level storage or delivery improvements may be needed to facilitate load control.

Key assumptions on irrigation load control include the following:

- KID and TID have publicly stated that large-scale load control could disrupt water deliveries, requiring yet-to-be-identified changes to the water distribution system.

- Load control tariffs are not developed or piloted; consequently, their ultimate definition, ability to participate, and durability are uncertain.

- District level changes needed in the TID, KID, and KDD to support a load control program are unknown. On-farm programs including water storage during outages may also be needed.

- KBRA funding would be used to optimize the water delivery and storage system to accommodate load control.

Table 5-20 presents the performance of irrigation load control evaluated against the screening criteria.

Table 5-20. Irrigation Load Control Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Irrigation Load Control	■ Excellent/Yes	■ Poor/No	■ Good	■ Fair/Tolerable	■ Excellent/Yes	■ Fair/Tolerable	■ Good	■ Good	■ Excellent/Yes

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.4 Efficiency and Equipment Improvements

Efficiency and equipment improvements are specifically called for in the KBRA. Efficiency improvements provide an excellent opportunity to reduce energy costs through replacement or rehabilitation of inefficient equipment. Economic benefits from efficiency and equipment improvements would be distributed to irrigators in Oregon and California in the form of overall power cost reductions for those with improved systems.

It is uncertain how KBRA funding would be distributed to assist with efficiency improvements. A revolving loan or grant fund could be established with KBRA and/or irrigator funding. Because some irrigators have already upgraded equipment and the costs for upgrading a system are highly variable, equitably distributing benefits would be challenging. Administrative efforts to track, distribute, and collect funds for improvement projects are anticipated to be high.

Key assumptions for energy efficiency improvements include the following:

- Overall Basin energy savings are projected at 9 to 30 percent with large scale pump equipment improvements.

- Distributing KBRA funds is uncertain; however, money in the form of incentives through PacifiCorp and Energy Trust of Oregon could be leveraged to reduce the irrigators' out of pocket expense.

- Energy efficiency directly offsets the cost of PacifiCorp power and consequently has a good ability to lower power costs.

Based on the stated assumptions, savings equal $1 million to $3 million annually. Table 5-21 presents the performance of efficiency and equipment improvements evaluated against the screening criteria.

Table 5-21. Efficiency and Equipment Improvements Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Efficiency/ Equipment Improvements	■	■	■	■	■	■	■	■	■

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.5 On-Project Plan

The KBRA requires KWAPA to develop the On-Project Plan (OPP) to address the water supply and demand balance for On-Project irrigators located in the On-Project Plan Area as a result of the KBRA's changes to water supply in the Klamath Basin. While the On-Project Plan Summary Report (KWAPA 2014a) and the OPP's Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR, currently under development) address water supply issues, the OPP options and alternatives were not formulated specifically to reduce energy or power costs for On-Project irrigators. The CAPP evaluation considers the OPP options that are components of the proposed program, as identified in Technical Memorandum 7, *Proposed On-Project Plan Program and Implementation and Administration*, of the OPP Report (KWAPA 2014b). KBRA funding could be used to fund options that also reduce energy usage.

Key assumptions for the OPP options include the following:

- While all OPP options are necessarily consistent with the KBRA, none benefit the Off-Project irrigators nor some of the On-Project Warren Act contractors.

- Some OPP options have no effect on power or could increase power consumption.

- Water Conservation and Efficiency Options:

  - Tulelake Sump 1A: Recirculation would decrease power costs because it would eliminate pumping at D-plant during March through August. To calculate actual power savings, pump operating conditions are needed for the two 45-cubic feet per second (cfs) axial pumps that lift water from D Plant to Check 5 in the J-1 canal.

  - Klamath Straits Drain (KSD) Flow to Lower Klamath National Wildlife Refuge (NWR): This option is potentially neutral from a power use perspective, as increased power to run the two new 45-cfs axial pumps to lift water from KSD to 6A canal offsets reduced pumping at E and EE, F and FF, and D Plants.

  - KBRA funding would be used to finance the project and for ongoing O&M costs to KWAPA.

  - The reduction in energy usage would be quantified and could be distributed by KWAPA to irrigators.

- Groundwater Options:

  - Permanent transitions from surface water to groundwater would likely require more power to pump groundwater.

  - Maximize Pumping Using Existing Wells Consistent with Current Configuration, Regulations, and Practice Option: This option provides groundwater substitution for Project water.

  - Interpretation and Revision of Oregon Water Resources Department (OWRD) Regulations in Oregon Option: This requires that KWAPA coordinate with OWRD to allow for revision or interpretation of existing regulations to provide for additional groundwater pumping in the Oregon portion of the OPP area.

  - Movement of Well Capacity to Strategic Locations within the OPP Area Option: KWAPA would fund new groundwater wells in more advantageous groundwater production areas and close wells with low production capacity due to interference from surrounding wells. If wells are located where the groundwater table is higher, it will reduce pumping costs.

- Additional Surface Water Availability Options: This involves permanent discontinuation of surface water use on areas that can rely exclusively on groundwater. This option applies only to very specific areas of the OPP area, so the distribution of benefits would not be equitable. Increased reliance on groundwater pumping will increase power use.

- Demand Management Options:

  - All land idling options are assumed to require long-term or perpetual agreements.

  - All options would have the potential to reduce power costs due to either full-year or partial-year reductions in irrigation.

Table 5-22 presents the performance of the OPP options evaluated against the screening criteria. Because specific savings cannot be calculated at this time, each option is evaluated on its ability to result in higher, lower, or neutral effects on power costs.

Table 5-22. OPP Option Screening Evaluation

OPP Option	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Effect on power costs (higher, lower, neutral)
Tule Lake Sump 1A	Excellent/Yes	Excellent/Yes	Poor/No	Poor/No	Good	Good	Low
KSD Flow to Lower Klamath NWR	Excellent/Yes	Excellent/Yes	Poor/No	Fair/Tolerable	Fair/Tolerable	Good	Neutral
Maximize pumping using existing wells consistent with current configuration, regulations, and practice	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Fair/Tolerable	High
Interpretation and revision of OWRD regulations in Oregon	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable	Good	Excellent/Yes	Neutral
Movement of well capacity to strategic locations within the OPP area	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Excellent/Yes	Low
Additional surface water availability	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Excellent/Yes	Excellent/Yes	High
Full-year land idling	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Good	Excellent/Yes	Low
Partial-year land idling	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Good	Excellent/Yes	Low

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.6 Pump Conversion to Natural Gas

Pump conversions to natural gas have been proposed as a method to lower energy costs. Pump conversions would occur on select irrigation properties in Oregon and California. Natural gas could be supplied through fixed lines or by on-site storage tanks. Oregon's natural gas utility in the Klamath Basin area, Avista, could provide piped natural gas to Oregon irrigation properties within its service area that are close to supply lines. All other properties would need to rely on on-site storage tanks. Since there is no natural gas utility service available to the California On-Project area, the area would need to rely on on-site storage.

Economic benefits from pump conversions would be difficult to distribute equally to irrigators, as benefits would be in the form of overall power cost reduction to the properties with pump conversions.

Key assumptions for pump conversion to natural gas include the following:

- Natural gas used to run pumps is not a renewable resource. Although it does not involve power development, it could be inconsistent with the KBRA.

- Economic benefits would be difficult to distribute equally to irrigators. Benefits would be highly variable, as the cost of conversion at each site depends on the availability of gas service and proximity to utility gas lines, or on-site gas storage and equipment size.

- No policies in either state preclude running irrigation pumps off natural gas. However, natural gas pumps would be required to meet Environmental Protection Agency and California Air Resources Board emission standards for off-road engines and could be subject to annual permitting fees from local air pollution districts.

- In general, natural gas-powered internal combustion engines are less durable and require more repair, maintenance, and service than electric motors. Natural gas engines typically have two-thirds or less the useful life of electric motors, and engine power loss due to engine wear during the useful life must be considered in initial engine sizing.

- Although costs vary greatly and will depend on location, natural gas engines typically have higher O&M costs than electric motors on a dollar per acre per year basis.

- Capital costs for pumps with internal combustion engine drives are several times the cost of an equivalent electric motor and pump and are available from significantly fewer manufacturers.

Table 5-23 presents the performance of pump conversion to natural gas evaluated against the screening criteria.

Table 5-23. Pump Conversion to Natural Gas Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Pump Conversion to Gas	■ (Poor/No)	■ (Excellent/Yes)	■ (Fair/Tolerable)	■ (Fair/Tolerable)	■ (Good)	■ (Poor/No)	■ (Fair/Tolerable)	■ (Fair/Tolerable)	■ (Fair/Tolerable)

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No

5.2.2.7 Out-of-Basin Investment in Renewable Energy Generation

Investment in renewable energy generation outside the Klamath Basin could be undertaken with KBRA funding, but at the time of TWG-4 it was uncertain whether this option was consistent with the KBRA. Economic benefits from investments in renewable energy generation could be distributed to all irrigators through an annual bill credit on an energy use pro-rata basis. To diversify risk, investment would be made in one or more renewable mutual funds or exchange traded funds, with the annual dividend used to fund the bill credit. Yield on these funds is generally less than five percent annually and is subject to volatility.

Key assumptions on out-of-Basin investment in renewable energy generation include the following:

- Basin irrigators would not be the owner/operator of an out-of-Basin renewables facility, which would require staffing, O&M, and power contracting.
- Forty million dollars in KBRA funding would be invested to yield an annual return.
- Assumed an annual energy usage of 118 million kWh in the Basin and an annual average 5 percent return made on a $40 million KBRA investment.
- 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.

Based on the stated assumptions, this option would yield $2 million in annual revenue, which would result in an annual rate reduction of approximately 16 percent in Oregon and 19 percent in California. If the percent return is lowered from 5 percent to 3 percent, then the option would yield $1.2 million in annual revenue and result in an annual rate reduction of approximately 9 percent in Oregon and 12 percent in California. Table 5-24 presents the performance of out-of-Basin investment in renewable energy generation evaluated against the screening criteria.

Table 5-24. Out-of-Basin Renewable Investment Option Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Out-of-Basin Renewable Investment	?	?	Excellent/Yes	Excellent/Yes	Good	Good	Fair/Tolerable	Good	Excellent/Yes

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No ?: Unknown

5.3 Results Summary

Tables 5-25 and 5-26 summarize the evaluation of the power development options and the demand management, investment, and alternate source development options, respectively, against the CAPP performance measures. Generally, options at the top of the tables performed best while options towards the bottom performed worst. The most important criteria are an option's ability to lower power costs or rates, followed by access to and distribution of benefits, as long as the option did not receive a poor (red) score for any criterion.

Table 5-25. Summary of Power Development Option Screening Evaluation

Option	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	LCOE ¢/kWh	Power Rates/Costs % Reduced OR	CA	Env. Impact
Utility-Scale Solar	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Good	Excellent/Yes	Excellent/Yes 1.89	Fair/Tolerable 7	Fair/Tolerable 9	Good
Small-Scale Solar (Net Metered)	Excellent/Yes	Good	Good	Fair/Tolerable	Excellent/Yes	Good	Excellent/Yes 1.98	Fair/Tolerable 16	Good 26	Excellent/Yes
Low-Head Hydro	Excellent/Yes	Excellent/Yes	Good	Fair/Tolerable	Fair/Tolerable	Excellent/Yes	Excellent/Yes 1.98	Fair/Tolerable 10	Fair/Tolerable 12	Fair/Tolerable
Progressive Utility-Scale Solar	Excellent/Yes	Poor/No	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Good	Excellent/Yes 1.92	Fair/Tolerable 19	Good 33	Good
Fuel Cells	Poor/No	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable	Good	Good	Fair/Tolerable 8.30	Good 33	?	Good
Geothermal - Conventional	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Good 4.56	Poor/No 3	Poor/No 4	Good
Geothermal – Enhanced	Excellent/Yes	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Poor/No 12.61	Poor/No -9	Poor/No -10	Good
Biofuels	Excellent/Yes	Excellent/Yes	Good	Good	Good	Fair/Tolerable	Good 4.56	Poor/No -24	Poor/No -29	Fair/Tolerable
Natural Gas Development > 5 MW	Poor/No	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Fair/Tolerable 7.90	Poor/No -16	Poor/No -19	Poor/No
Natural Gas Development < 5 MW	Poor/No	Excellent/Yes	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Poor/No 9.20	Poor/No -17	Poor/No -21	Poor/No

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No ?: Unknown

Table 5-26. Summary of Demand Management, Investment, and Alternative Source Development Option Screening Evaluation

Option	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Power Rates/Costs OR	Power Rates/Costs CA	Env. Impact
Efficiency/equipment improvements	Excellent/Yes	Excellent/Yes	Good	Fair/Tolerable	Fair/Tolerable	Excellent/Yes	Good	Good	Excellent/Yes
Irrigation load control	Excellent/Yes	Poor/No	Good	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Good	Good	Excellent/Yes
Out-of-Basin renewable investment	?	?	Excellent/Yes	Excellent/Yes	Good	Good	Fair/Tolerable	Good	Excellent/Yes
Time-of-use	Excellent/Yes	Fair/Tolerable	Good	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Excellent/Yes
Pump conversion to natural gas	Poor/No	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Poor/No	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable
Federal power	Excellent/Yes	Good	Poor/No	Poor/No	Fair/Tolerable	Excellent/Yes	Fair/Tolerable	Poor/No	Excellent/Yes
OPP Options									
Movement of well capacity to strategic locations within the OPP area	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Excellent/Yes	Low		**NA**
Full-year land idling	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Good	Excellent/Yes	Low		**NA**
Partial-year land idling	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Good	Excellent/Yes	Low		**NA**
Tule Lake Sump 1A	Excellent/Yes	Excellent/Yes	Poor/No	Poor/No	Good	Excellent/Yes	Low		**NA**
KSD flow to Lower Klamath NWR	Excellent/Yes	Excellent/Yes	Poor/No	Fair/Tolerable	Fair/Tolerable	Good	**Neutral**		**NA**
Interpretation and revision of OWRD regulations in Oregon	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Fair/Tolerable	Good	Excellent/Yes	**Neutral**		**NA**
Maximize pumping using existing wells consistent with current configuration, regulations, and practice	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Fair/Tolerable	Good	Fair/Tolerable	**High**		**NA**
Additional surface water availability	Excellent/Yes	Excellent/Yes	Fair/Tolerable	Poor/No	Excellent/Yes	Excellent/Yes	**High**		**NA**

Legend: ■: Excellent/Yes ■: Good ■: Fair/Tolerable ■: Poor/No ?: Unknown Low: Low effect on power costs Neutral: Neutral effect on power costs High: High effect on power costs NA: Not evaluated

Technical Workgroup Meeting #4

TWG-4 was held on April 17, 2015 in the KWAPA/Klamath Water Users Association conference room in Klamath Falls, Oregon. A webinar was held simultaneously for those who could not attend in person.

Purpose

The purpose of this meeting was to present the screening criteria and metrics, present the initial screening of all CAPP options, and brainstorm initial alternatives.

Major Outcomes and Decisions

The TWG suggested that an option should not be screened out if it is inconsistent with the KBRA or current policies and that the analysis should account for money withheld to reinvest in the replacement of an option. It was also suggested that the next level of analysis investigate the external benefits of each alternative, such as providing jobs, money, and tax savings to the community.

Power development options that exhibited strong negative power cost reduction potential were eliminated from consideration. Further policy input was needed by the technical team for options inconsistent with the KBRA and options requiring changes in State policies (e.g., progressive solar) to be viable.

Table 5-27 presents the status of CAPP options based on the option screening evaluation and input received at TWG-4.

Table 5-27. CAPP Options Retained or Removed from Further Analysis

Retained	Removed
• Geothermal – conventional • Utility-scale solar • Progressive utility-scale solar • Low-head hydro • Small-scale solar • Fuel cells • Federal power • Time-of-use • Irrigation load control • Efficiency/equipment improvements • Out-of-Basin investment • OPP Options (except two that were removed)	• Natural gas development • Biofuels • Geothermal – enhanced • Pump conversion to natural gas[4] • Maximize pumping using existing wells consistent with current configuration, regulations, and practice (OPP) • Additional surface water availability (OPP)

[4] Shortly after TWG-4, stakeholders requested natural gas pump conversions be retained and further evaluated following news of a potential supply of natural gas from the Pacific Connector gas pipeline.

Chapter 6
Alternatives Formulation and Initial Screening

This chapter outlines the process used to formulate alternatives, describes the preliminary alternatives and their review with stakeholders, evaluates their performance against screening criteria, and summarizes the screening results.

Through the screening analysis described in Chapter 5 and feedback obtained from the Technical Work Group (TWG), the retained Klamath Comprehensive Agricultural Power Plan (CAPP) options were combined into 12 preliminary alternatives. Options were grouped based on complementary benefits that could, for the group, result in increased performance against screening criteria.

6.1 Screening Criteria

The screening criteria used to evaluate the preliminary alternatives are the same as those developed for the options, described in Section 5.1. The only difference is that levelized cost of energy was removed as a criterion and replaced with a more precise estimate of energy production and the value of the energy developed. The remaining criteria used for analysis of the alternatives include:

- Consistency with the KBRA
- Consistency with regulations and policies
- Access to benefits
- Distribution of benefits
- Administrative intensity
- Durability
- Ability to reduce power rates/costs
- Environmental impact

6.2 Preliminary Alternatives

This section summarizes each preliminary alternative and describes the economic and other benefits, uncertainties, and potential environmental effects. Many of the alternatives share common assumptions and uncertainties. These are listed below, and for brevity are not listed with the alternative. Further work is being conducted to reduce many of these common uncertainties.

Common Uncertainties:

- PacifiCorp's ability to provide a bill credit to eligible irrigators and the appropriate bill credit basis

- For power development alternatives, interconnection location and costs

Common Assumptions:

- For revenue generation alternatives, energy sold to PacifiCorp at the 2015 average avoided cost rate of 3.4 ¢/kWh

6.2.1 Alternative 1: Utility-Scale Solar

Alternative 1 would develop approximately 15.4 megawatts (MW) of solar photovoltaic (PV) electricity using single axis tracking technology at single or multiple distributed sites with a Klamath Basin Restoration Agreement (KBRA)-funded initial investment of $40 million. The power would be sold to PacifiCorp through a power purchase agreement (PPA). This amount of solar would exceed PacifiCorp's Renewable Portfolio Standard (RPS) requirements, and therefore would likely be purchased at their avoided cost. The revenue would be used to reduce project participants' energy costs through a bill credit.

Figure 6-1. Example of a Utility-Scale Solar Facility

Economic Benefits

- Yields approximately $960,000 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 cents per kilowatt-hour (¢/kWh).
- The projected annual rate reduction would be seven percent in Oregon and nine percent in California using a bill credit.

Other Benefits and Features

- A 15.4-MW facility would produce 40.4 million kWh annually.
- Invests in the Basin economy through jobs.
- As an element of a future microgrid, would provide energy resiliency and grid independence.
- Future conversion to shared solar would be possible when supported by regulatory policies.
- Former Department of Defense Back Scatter sites in Oregon and California may provide good solar PV siting locations.

Uncertainties

- Development locations and interconnection costs

Potential Environmental Effects

The facility or facilities would cover an average area of approximately 125 acres (at approximately eight acres per installed MW), potentially removing productive farm land, disrupting sensitive terrestrial flora and fauna, and resulting in visual impacts. Environmental impacts could be minimized if facilities are sited on disturbed or non-arable land.

Alternative Screening Evaluation

Alternative 1 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-1.

Table 6-1. Alternative 1 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ (Excellent)	■ (Excellent)	■ (Excellent)	■ (Excellent)	■ (Good)	■ (Excellent)	■ (Fair/Tolerable)	■ (Fair/Tolerable)

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2 Alternative 2: Low-Head Hydropower

Alternative 2 would develop up to 4 MW of low-head hydroelectric power (hydro) at one or more sites using a KBRA-funded initial investment of $40 million. The power would be sold to PacifiCorp through a power purchase agreement, likely at their avoided cost. The delivered power revenue would provide a revenue stream to reduce energy costs through a bill credit.

The Klamath Project area has several potential locations for low-head hydro resources. The hydro sites discussed below were evaluated and could be developed, depending on site specific cost evaluations. There are uncertainties common to each option, including:

- The estimated capital cost is a conceptual-level construction cost for a new facility based on published data or extrapolated costs from other projects with a similar generating capacity.
- Detailed layouts or quantity takeoffs were not prepared.

Consequently, a contingency of 25 percent was included with each option.

6.2.2.1 Keno Dam

PacifiCorp's Keno Dam is located on the Link River, approximately 20 miles downstream of Link River Dam. The dam controls Keno Reservoir, the upper-end impounded reach of the Klamath River. The Klamath Hydroelectric Settlement Agreement (KHSA) calls for transferring ownership and operation of Keno Dam from PacifiCorp to the U.S. Department of the Interior. Hydropower was never installed at this facility; however, an affirmative determination by the Secretary of the Interior on the KHSA could allow the installation of low-head hydropower at Keno Dam. Flows through Keno Dam are not seasonal, although the summer and fall rates decrease due to the seasonal decreases in Link River flow rates.

Hydro development at Keno Dam, depicted in Figure 6-2, will require the following improvements:

- Substantial dam modification for a flow control diversion on the east side
- A new fish screen structure to ensure compliance with Endangered Species Act (ESA) requirements
- A small penstock to capture greater head, routed on the east side
- Upgrades to the existing electrical distribution line serving the site

Figure 6-2. Depiction of Low-Head Hydro at Keno Dam

Table 6-2 presents the design criteria for low-head hydro development at Keno Dam.

Table 6-2. Keno Dam Design Criteria

Design Element	Units
Flow	1,350 cfs
Design Head	38 feet
MW Size	3.8 MW
Capacity Factor	82.5%
Annual Energy Production	27.4 GWh
Annual Gross Revenue	$931,400
Annual O&M	$113,700
Net Annual Revenue	$817,700
Capital Cost	$35.9 million

Key: cfs = cubic feet per second; GWh = gigawatt-hours
Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $817,700 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.

- The ratio of capital cost to net revenue is 44:1, the lowest of the six low-head hydro options.

Other Benefits and Features

- 3.8-MW facility produces 27 GWh annually

- Potential to tie into PacifiCorp’s existing distribution lines
- Existing dam facilities are used and expanded, lowering costs
- Investment in the Basin economy through jobs

Uncertainties

- Foundation geology for penstock and powerhouse stability
- Interconnection requirements
- Fish passage and protection requirements with the KHSA for sucker and Coho and Chinook salmon
- Federal versus non-Federal ownership will affect permitting requirements

Potential Environmental Effects

Low-head hydro at Keno Dam will require fish passage and protection measures for ESA-listed sucker and Coho. Site operation and design would be subject to consultation with the U.S. Fish and Wildlife Service (USFWS) and the National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS).

Alternative Screening Evaluation

Low-head hydro at Keno Dam was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-3. This hydro site is highly viable, however the final design and operations necessary to accommodate sucker and salmon are uncertain.

Table 6-3. Hydro at Keno Dam Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	Excellent	Good	Good	Good	Good	Good	Fair/Tolerable	Fair/Tolerable

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.2 Westside Powerhouse

PacifiCorp's Westside Powerhouse is located on the Link River, and receives water diverted into its canal and penstock from the Klamath River at the Bureau of Reclamation's (Reclamation’s) Link River Dam. Flows through Westside Powerhouse are not seasonal, although the summer and fall flow rates decrease due to the seasonal decreases in river flow rates. This project, depicted in Figure 6-3, would include the following features:

- A new fish screen on the inlet for sucker near the canal entrance at Link River Dam
- Reuse of the existing diversion canal
- Fully-replaced powerhouse due to uncertain conditions and equipment sizing
- Reuse of existing substation
- A new tailrace barrier for sucker and salmon

Figure 6-3. Project Depiction of Low-Head Hydro at Westside Powerhouse

Table 6-4 presents the design criteria for low-head hydro development at the Westside Powerhouse.

Table 6-4. Westside Powerhouse Design Criteria

Design Element	Units
Flow	250 cfs
Design Head	28.5 feet
MW Size	0.53 MW
Capacity Factor	82.5%
Annual Energy Production	3.8 GWh
Annual Gross Revenue	$129,400
Annual O&M Cost	$ 15,800
Net Annual Revenue	$113,600
Capital Cost	$5.8 million

Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $113,600 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- The ratio of capital cost to net revenue is 51:1, the second lowest of the six low-head hydro options.

Other Benefits and Features

- 0.5-MW facility produces 3.8 GWh annually
- Ties into the existing substation and distribution lines
- Uses existing water canal to the extent possible
- Investment in the Basin economy through jobs

Uncertainties

- Ability of Reclamation or another entity to lease or purchase the site from PacifiCorp
- Facility acquisition cost
- Substation refurbishing costs
- Fish protection requirements with the KHSA for sucker and Coho and Chinook salmon

Potential Environmental Effects

Low-head hydro at Westside Powerhouse will require a fish screen and tailrace barrier for ESA-listed sucker and Coho. Site operation and design would be subject to consultation with USFWS and the NMFS.

Alternative Screening Evaluation

Table 6-5 presents the screening evaluation for low-head hydro at Westside Powerhouse. This alternative also has uncertainties regarding the final design to accommodate sucker and salmon.

Table 6-5. Hydro at Westside Powerhouse Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ (Excellent)	■ (Excellent)	■ (Good)	■ (Good)	■ (Good)	■ (Good)	■ (Fair/Tolerable)	■ (Fair/Tolerable)

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.3 Eastside Powerhouse

PacifiCorp's Eastside Powerhouse is located on the Link River, and receives water diverted into its canal and penstock from the Klamath River at Reclamation's Link River Dam. This facility could be served from its existing intake with a new fish screen or by supplying the facility off the A Canal. Flows through Eastside Powerhouse are not seasonal, although the summer and fall flow rates decrease due to the seasonal decreases in river flow rates. This option, depicted in Figure 6-4, would include the following features:

- A new fish screen on the diversion entrance at Link River Dam
- Reuse of the existing diversion and penstock
- Fully-replaced powerhouse due to uncertain conditions and equipment sizing
- New tailrace barrier for sucker and salmon

Figure 6-4. Eastside Powerhouse

Table 6-6 presents the design criteria for low-head hydro development at Eastside Powerhouse.

Table 6-6. Eastside Powerhouse Design Criteria

Design Element	Units
Flow	1,200 cfs
Design Head	26.6 feet
MW Size	2.23 MW
Capacity Factor	76.5%
Annual Energy Production	14.9 GWh
Annual Gross Revenue	$507,500
Annual O&M Cost	$66,800
Net Annual Revenue	$440,700
Capital Cost	$24.6 million

Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $440,700 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- The ratio of capital cost to net revenue is 56:1, the fourth lowest of the six low-head hydro options.

Other Benefits and Features

- 2.2-MW facility produces 14.9 GWh annually
- Investment in the Basin economy through jobs
- Ties into existing distribution lines
- Uses the existing penstock and surge tank to the extent possible

Uncertainties

- Ability of Reclamation or another entity to lease or purchase the site from PacifiCorp
- Facility acquisition cost
- Interconnection and control upgrade costs
- Substation refurbishing costs
- Fish protection requirements with the KHSA for sucker and Coho and Chinook salmon

Potential Environmental Effects

Low-head hydro at Eastside Powerhouse will require a fish screen and tailrace barrier for ESA-listed sucker and Coho. Site operation and design would be subject to consultation with USFWS and the NMFS.

Alternative Screening Evaluation

Table 6-7 presents the screening evaluation for low-head hydro at Eastside Powerhouse. This alternative also has uncertainties regarding the final design to accommodate sucker and salmon.

Table 6-7. Hydro at Eastside Powerhouse Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ (Excellent)	■ (Excellent)	■ (Good)	■ (Good)	■ (Good)	■ (Good)	■ (Fair/Tolerable)	■ (Fair/Tolerable)

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.4 Eastside Powerhouse with A Canal Water

This option is similar to the Eastside Powerhouse option but would use a diversion off Reclamation's A Canal, eliminating the need for a new fish screen on the inlet. It would require a new pipeline from the A Canal to the powerhouse. The existing Reclamation fish screen on the A Canal is rated for 1,150 cfs. The proposed arrangement would divert powerhouse flow to the A Canal through a pipeline to the Eastside Powerhouse. Flows through Eastside Powerhouse using A Canal water would be seasonal, limited to the seasonal irrigation flow rates being diverted from the A Canal.

This project, depicted in Figure 6-5, would include the following features:

- Diverted A Canal water from below the fish screen to the Eastside Powerhouse diversion, routed through the edge of the lake
- Reuse of the existing diversion and penstock
- Full replacement of the existing powerhouse due to uncertain conditions and generator sizing
- New tailrace barrier for sucker and salmon

Figure 6-5. Eastside Powerhouse Using A Canal Water

Table 6-8 presents the design criteria for low-head hydro development at Eastside Powerhouse with A Canal Water.

Table 6-8. Eastside Powerhouse Using A Canal Water Design Criteria

Design Element	Units
Flow	1,100 cfs
Design Head	27 feet
MW Size	2.19 MW
Capacity Factor	60%
Annual Energy Production	11.5 GWh
Annual Gross Revenue	$392,200
Annual O&M Cost	$65,800
Net Annual Revenue	$326,300
Capital Cost	$17.0 million

Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $326,300 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.

- The ratio of capital cost to net revenue is 52:1, the third lowest of the six low-head hydro options.

Other Benefits and Features

- A 2.2-MW facility produces 11.5 GWh annually.
- Would invest in the Basin economy through jobs.
- Irrigation diversions, in addition to hydropower diversion, could be directed to the Eastside Powerhouse, increasing energy output with the water recaptured at the Lost River Diversion.
- Ties into existing distribution lines.

Uncertainties

- Ability of Reclamation or another entity to lease or purchase the site from PacifiCorp
- Canal diversion and pipeline alignment
- Interconnection and control upgrades
- Fish protection requirements for sucker and Coho and Chinook salmon with the KHSA

Potential Environmental Effects

Low-head hydro at Eastside Powerhouse will require a tailrace barrier for ESA-listed sucker and Coho. Site operation and design would be subject to consultation with USFWS and the NMFS.

Alternative Screening Evaluation

Table 6-9 presents the screening evaluation for low-head hydro at Eastside Powerhouse with A Canal water. This alternative also has uncertainties regarding the final design to accommodate sucker and salmon.

Table 6-9. Hydro at Eastside Powerhouse with A Canal Water Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■	■	■	■	■	■	■	■

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.5 A Canal

At the A Canal just downstream from the Reclamation fish screen, the irrigation water flows through an open channel and then through a tunnel before entering the Klamath Irrigation District (KID) distribution system. This option would provide a covered channel and a powerhouse adjacent to the upper tunnel entrance. Flows through the A Canal are seasonal, with flow rates and generation dependent on A Canal irrigation flow rates.

This project, shown in Figure 6-6, would include the following features:

- Replacement of existing irrigation channel with a covered channel or penstock
- New powerhouse at the upper end of the tunnel
- New power distribution line interconnection

Figure 6-6. A Canal Powerhouse

Table 6-10 presents the design criteria for low-head hydro development at A Canal Powerhouse.

Table 6-10. A Canal Powerhouse Design Criteria

Design Element	Units
Flow	1,100 cfs
Design Head	11.4 feet
MW Size	0.93 MW
Capacity Factor	60%
Annual Energy Production	4.9 GWh
Annual Gross Revenue	$165,600
Annual O&M Cost	$27,800
Net Annual Revenue	$137,800
Capital Cost	$10.5 million

Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $137,800 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- The ratio of capital cost to net revenue is 76:1, the second highest cost of the six low-head hydro options.

Other Benefits and Features

- Produces 4.9 GWh annually.
- Invests in the Basin economy through jobs.
- Uses the existing fish screen facilities.
- Eliminates the existing hazardous slope of the upper A Canal.

Uncertainties

- Development costs for a new covered channel
- Power and control interconnection

Potential Environmental Effects

The facility would divert canal water, potentially affecting canal flows, but overall environmental effects are expected to be minor.

Alternative Screening Evaluation

Table 6-11 presents the screening evaluation for low-head hydro at A Canal. This alternative also has uncertainties regarding the final design to accommodate sucker and salmon.

Table 6-11. Hydro at A Canal Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■	■	■	■	■	■	■	■

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.6 G Canal

The G Canal splits from the C Canal and passes under the Lost River in a pipe/siphon arrangement in the KID service area. A small hydro system could be developed at the south end of the siphon. Flows through a G Canal hydro plant would be seasonal, with flow rates and generation dependent on G Canal irrigation flow rates.

This project, shown in Figure 6-7, would include the following features:

- Reuse of the existing canal or a new covered canal
- New powerhouse at the south end of the siphon
- New power interconnections

Figure 6-7. G Canal Powerhouse

Table 6-12 presents the design criteria for low-head hydro development at G Canal Powerhouse.

Table 6-12. G Canal Design Criteria

Design Element	Units
Flow	310 cfs
Design Head	11.4 feet
MW Size	0.26 MW
Capacity Factor	60%
Annual Energy Production	1.4 GWh
Annual Gross Revenue	$46,700
Annual O&M Cost	$7,800
Net Annual Revenue	$38,800
Capital Cost	$4.3 million

Note: The values presented in this table are rounded.

Economic Benefits

- Yields approximately $38,800 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- The ratio of capital cost to net revenue is 111:1, the highest of the six low-head hydro options.

Other Benefits and Features

- 0.3-MW facility produces 1.4 GWh annually.
- Invests in the Basin economy through jobs.

Uncertainties

- Development and interconnection costs
- Siphon rework and canal flow controls

Potential Environmental Effects

The facilities would use irrigation canal water, potentially affecting canal flows, but overall environmental effects are anticipated to be minor.

Alternative Screening Evaluation

Table 6-13 presents the screening evaluation for low-head hydro at G Canal.

Table 6-13. Hydro at G Canal Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	Excellent	Excellent	Good	Good	Good	Excellent	Fair/Tolerable	Good

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.2.7 Comparison of Low-Head Hydro Options

The low-head hydro power options can be evaluated further by comparing costs and energy production. Table 6-14 presents project cost, annual power energy production, cost per GWh, expected yearly net revenue from power sales, and the ratio of project cost to annual net revenue. The options are listed from lowest cost-to-revenue ratio to highest. The comparative ratings show the Keno Dam and the Westside Powerhouse projects would provide the most revenue per project dollar invested of the six options.

Table 6-14. Summary of Cost, Energy, and Revenue for Low-Head Hydro Options

Hydro Option Site	Project Cost ($ million)	Annual Energy Production (GWh)	Cost per GWh ($ million/ GWh)	Annual Net Revenue ($)	Ratio of Project Cost to Annual Net Revenue
Keno Dam	35.9	27.4	1.31	817,700	44
Westside Powerhouse	5.8	3.8	1.52	113,600	51
Eastside with A Canal Water	17.0	11.5	1.47	326,300	52
Eastside Powerhouse	24.6	14.9	1.65	440,700	56
A Canal	10.5	4.9	2.16	137,800	76
G Canal	4.3	1.4	3.13	38,800	111

6.2.3 Alternative 3: Out-of-Basin Investment

Alternative 3 would invest $40 million of KBRA funding in pure-play renewable energy assets through a yieldco. A yieldco is a dividend-yielding public company that bundles renewable energy and/or conventional assets that generate a predictable cash flow from long-term contracts on the operating asset. The yieldco then distributes yearly cash dividends to its shareholders. Yieldcos are a recent investment mechanism, with six formed since 2013, and are attractive to shareholders for their low-risk returns that increase over time as the asset depreciates. Yieldcos are structured to avoid double-taxation similar to a Real Estate Investment Trust (REIT). While typical investments are taxed twice (once at the corporate level and again at the shareholder level), the yieldco passes its untaxed earnings on to the investor (Urdanick 2014). Essentially, the shareholder owns a minority interest in the generation asset through the yieldco, as depicted in Figure 6-8.

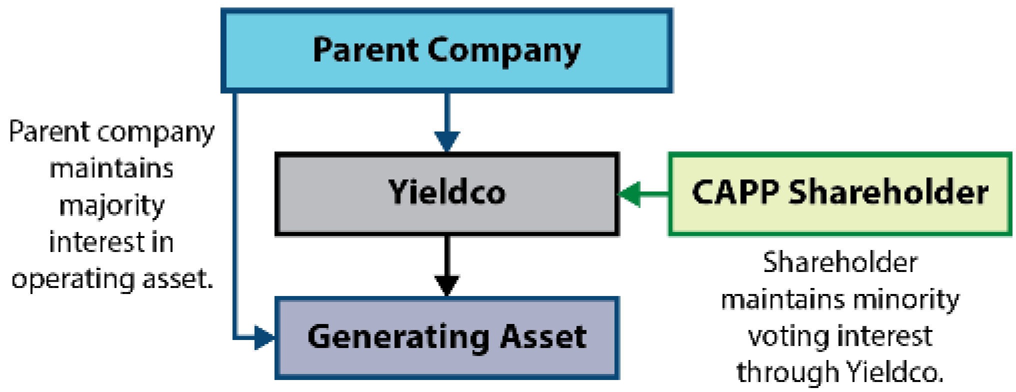


Figure 6-8. Yieldco Financial Structure

When compared to conventional mutual funds or exchange traded funds, the yieldco guarantees that the CAPP investment is made in purely renewable assets, as required by the KBRA. Four pure-play yieldcos operate in the United States, as shown in Table 6-15, with an average yield of four percent. Economic benefits from a yieldco investment would be distributed to all irrigators through an annual bill credit.

Table 6-15. Pure-Play Renewable Yieldcos and Reported Annual Dividend

Company	Year Established	Symbol	Energy Sector	Dividend
TransAlta Renewables, Inc.	2013	TSX:RNW	Wind and hydropower	6.6%
Pattern Energy Group, Inc.	2013	NASDAQ:PEGI	Wind	4.2%
NexEra Energy Partners	2014	NYSE:NEP	Diversified renewables	2.2%
TerraForm Power, Inc.	2014	NASDAQ:TERP	Solar	2.9%

Source: Becker 2014

Economic Benefits

- Provides an estimated $1.6 million in annual revenues at an average four percent yield.

- Results in an annual rate reduction of approximately 13 percent in Oregon and 16 percent in California.

Other Benefits and Features

- Low risk investment mechanism in pure renewables

Uncertainties

- Public perception of out-of-Basin investment

Potential Environmental Effects

Alternative 3 has no environmental effects because no facilities are associated with this alternative other than the facilities contained within the portfolio.

Alternative Screening Evaluation

Alternative 3 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-16.

Table 6-16. Alternative 3 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■	■	■	■	■	■	■	■

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.4 Alternative 4: Utility-Scale Solar and Out-of-Basin Investment

Alternative 4 would develop approximately 7.7 MW of solar PV electricity using single axis tracking technology at one or two distributed sites with half of the $40 million initial investment funded by the KBRA. The power would be sold to PacifiCorp through a PPA. This amount of solar would exceed PacifiCorp's RPS requirements and therefore would likely be purchased at their avoided cost. The revenue would be used to reduce project participants' energy costs through a bill credit. Figure 6-9 depicts a utility-scale solar array.

Figure 6-9. Utility-Scale Solar Array

The other half of the KBRA funding would be invested in renewable energy through a yieldco that produces an annual yield estimated at four percent of the investment. Section 6.2.3 provides a full description of a yieldco under Alternative 3, Out-of-Basin Investment. Economic benefits from these investments would be distributed to all project participants through an annual bill credit.

Economic Benefits

- Utility-scale PV site(s) would yield approximately $480,000 in annual net revenue, based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- Yieldco investment is projected to earn $800,000 annually through a four percent dividend on $20 million.
- The projected annual rate reduction is 10 percent in Oregon and 12 percent in California through bill credits.

Other Benefits and Features

- 7.7-MW solar PV facility produces 20.2 million kWh annually.
- Invests in the Basin economy through jobs.

- As an element of a future microgrid, would provide energy resiliency and grid independence.
- Future conversion to shared solar would be possible when supported by regulatory policies.
- Former Department of Defense Back Scatter sites in Oregon and California may provide good PV solar siting locations.

Uncertainties

- Development locations and interconnection costs
- Stability of renewable energy investment market

Potential Environmental Effects

The facility or facilities would cover an average area of approximately 60 acres (at roughly 8 acres per installed MW), potentially removing productive farm land, disrupting sensitive terrestrial flora and fauna, and resulting in visual impacts. Environmental impacts could be reduced if the facilities were sited on disturbed or non-arable land.

Alternative Screening Evaluation

Alternative 4 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-17.

Table 6-17. Alternative 4 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ Excellent	■ Excellent	■ Excellent	■ Excellent	■ Good	■ Excellent	■ Good	■ Good

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.5 Alternative 5: Geothermal

Alternative 5 would develop approximately 7 MW of electricity using conventional geothermal technology through a $40 million initial investment funded by the KBRA. The power would be sold to PacifiCorp through a PPA at the avoided cost. The revenue would be used to reduce energy costs through a PacifiCorp bill credit or other reimbursement mechanism. Conventional geothermal technology is illustrated in Figure 6-10.

Conventional Geothermal

Conventional geothermal technology provides "heat from the Earth" by pumping hot water from geothermal reservoirs to create steam, which is then used to spin turbines, creating mechanical energy, which is then converted to electricity.

Figure 6-10. Illustration of Conventional Geothermal Technology

Economic Benefits

- Yields approximately $403,000 in annual net revenue based on sale to PacifiCorp at an average avoided cost rate of 3.4 ¢/kWh.
- Projected annual rate reduction is three percent in Oregon and four percent in California.

Other Benefits and Features

- 7-MW facility produces 50.5 million kWh annually.
- Invests in the Basin economy through jobs.
- Electricity produced is relatively clean (one-sixth of the carbon dioxide emissions of a natural gas-fueled power plant).

Uncertainties

- Development and exploration costs and location, well costs, and interconnection costs: outreach to existing Basin geothermal developers found that none were willing to form expanded partnerships or divest of existing geothermal wells.
- Profitability is highly related to well field conditions (e.g., pressure, temperature, and steam).

Potential Environmental Effects

The facility would likely affect land use, air quality, geological resources, ecological resources, and water quality. Geothermal fluids are usually high in dissolved minerals and metals, requiring ongoing water quality monitoring of surface water and groundwater.

Alternative Screening Evaluation

Alternative 5 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-18. Well field development costs could be substantially greater than projected, reducing the net benefits of this technology.

Table 6-18. Alternative 5 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■	■	■	■	■	■	■	■

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.6 Alternative 6: Shared Solar

Alternative 6 would develop approximately 12 MW of solar PV electricity using single axis tracking technology at multiple distributed sites through a $40 million KBRA-funded initial investment. Shared solar development is utility-scale solar that allows for community meter aggregation or virtual metering. Solar power would be developed at 25 to 50 generating facilities, each serving 50 to 100 virtual meters. Power would be transmitted to PacifiCorp and renewable energy bill credits (per kWh) would be applied to the meters of participating irrigators.

Current policies do not allow virtual metering or aggregation in Oregon and it is not required of PacifiCorp in California. KBRA Section 17.4.7, Net Metering, states that aggregation of loads and other “arrangements” are anticipated and that the parties agree to cooperate to develop net metering arrangements with PacifiCorp and to “support any Regulatory Approvals that may be required.” Modifying regulatory policies in Oregon and California to allow shared solar offers an excellent opportunity to lower power costs.

Examples of Shared Solar Programs in California and Colorado

Sacramento Municipal Utility District's SolarShares Program

The Sacramento Municipal Utility District (SMUD) allows its customers to join a shared solar program called SolarShares. The SolarShares program allows customers to purchase up to 4 kW of the energy generated from a 1-MW solar PV installation, which produces about 1,736 MWh annually, in increments of 0.5 kW. SMUD then provides the customer a monthly energy credit for the electricity produced at the customer's full retail rate, directly offsetting energy costs. Participation costs typically range between $5 and $65 per month, depending on the customer's historical energy use and selected share size. For more information on the SolarShares program, visit https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/.

Clean Energy Collective, LLC Community Solar Development in Boulder, Colorado

Clean Energy Collective, LLC is a private, community/ shared solar developer responsible for several community solar projects in Colorado, New Mexico, and Minnesota. Their Boulder Cowdery Meadows Community Solar Array in Boulder, Colorado is a 496-kW solar PV project. Customers purchase a share of the solar PV system for $3.35 per watt and receive quarterly checks for their share of the energy produced on a $/kWh basis. A customer who purchased 20 solar PV panels reported typically receiving $150 quarterly. For more information on the Clean Energy Collective LLC and their projects, visit http://cleaneasyenergy.com/cecblog/index.php/category/cec-projects/.

Economic Benefits

- Annual savings equal approximately $2.7 million based on offsetting electricity supplied by PacifiCorp at the rates set in Schedules 41 and PA-20 in Oregon and California, respectively.
- Projected annual rate reduction is 19 percent in Oregon and 33 percent in California.

Other Benefits and Features

- 12-MW facility produces 28.9 million kWh annually.
- Each of the 25 to 50 generating facilities credits multiple meters.
- Invests in the Basin economy through jobs.
- As an element of a future microgrid, provides energy resiliency and grid independence.

Uncertainties

- Approval of new Oregon and California regulatory policies allowing shared solar and the content and timing of these policies
- Development locations and interconnection costs

- PacifiCorp's ability to advance shared solar programs such as community meter aggregation or virtual metering in the Basin

Potential Environmental Effects

The facilities would cover an average area of approximately 95 acres (8 acres per MW), potentially removing productive farm land, disrupting sensitive terrestrial flora and fauna, and resulting in visual impacts. Figure 6-11 presents an example of the installation of solar arrays at such a facility.

Figure 6-11. Installation of Utility-Scale Solar Arrays at Shared Solar Facility

Alternative Screening Evaluation

Alternative 6 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-19.

Table 6-19. Alternative 6 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	Excellent	Poor	Excellent	Excellent	Fair/Tolerable	Good	Good	Good

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.7 Alternative 7: Utility-Scale and Net Metered Solar

Alternative 7 combines utility-scale solar development with net metered solar, leveraging Oregon and California net metering incentives. Approximately half of the $40 million KBRA-funded initial investment would be used to develop one or two utility-scale solar PV projects. This alternative would develop approximately 7 to 8 MW of solar PV using single axis tracking technology. The power would be sold to PacifiCorp through a PPA. This amount of solar would exceed PacifiCorp's RPS requirements, and therefore would likely be purchased at their avoided cost. The revenue would be used to reduce project participants' energy cost through a bill credit.

The other half of the KBRA funding would be used to install net metered, small-scale solar PV systems at select irrigation pumps. Net metering is a system in which excess electricity generated by an eligible generator is fed back to the power grid, offsetting the electricity supplied by a utility. To provide as many PV systems as possible, the size of the systems would be limited to 5 kW. A 5-kW system would cost approximately $19,000, with an estimated cost of $3,800 per installed kW, and could fit on a typical residential or barn roof. Funding of $20 million could provide 1,050 systems serving approximately 40 percent of the Basin pumps.

Economic Benefits

- Utility-scale PV site(s) would yield approximately $480,000 in annual net revenue based on sale to PacifiCorp at average avoided cost rate of 3.4 ¢/kWh.

- Net metered solar PV systems are expected to produce about 8,360 kWh per year per system, offsetting about $800 in Oregon and $1,000 in California per system, based on current PacifiCorp rates in Schedules 41 (9.674 ¢/kWh) and PA-20 (12.933 ¢/kWh), respectively.

- Annual savings would be approximately $935,000 in Oregon and $429,000 in California.

- Revenue generated by the utility-scale PV site(s) would be used to fund programs at the discretion of the CAPP Management Entity and could include lower rates for select irrigators through a bill credit, investment in efficiencies, or CAPP management activities.

Other Benefits and Features

- 7.5-MW facility produces 20.2 million kWh annually.

- 1,050 individual 5-kW PV systems would produce 8.8 million kWh annually.

- Invests in the Basin economy through renewable energy jobs.

- As an element of a future microgrid, provides energy resiliency and grid independence.
- Future conversion to shared solar is possible when supported by regulatory policies.
- Former Department of Defense Back Scatter sites in Oregon and California may provide good PV solar siting locations.
- Large investment in small solar could recognize economy of scale, likely providing a reduced installation cost below that used in this analysis ($3,800 per installed kW).

Uncertainties

- Development locations and interconnection costs for utility scale solar
- Number of net metered systems allowed per irrigator and specific sizing

Potential Environmental Effects

The utility-scale facility or facilities would cover an area of approximately 60 acres (8 acres per MW), potentially removing productive farm land or disrupting sensitive terrestrial flora and fauna and resulting in visual impacts. Environmental impacts could be reduced if facilities were sited on disturbed or non-arable land. Individual net meter sites would have small dispersed footprint impacts.

Alternative Screening Evaluation

Alternative 7 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-20.

Table 6-20. Alternative 7 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ Excellent	■ Excellent	■ Excellent	■ Excellent	■ Good	■ Excellent	■ Good	■ Good

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.8 Alternative 8: Net Metering

Alternative 8 would develop approximately 4 to 8 MW of electricity using a combination of small-scale solar PV systems and natural gas-powered fuel cells. Solar PV would be funded through the KBRA while fuel cells would be funded by a low interest repayment plan through Reclamation or another source. The power generated by these systems would be net metered, offsetting the cost of the electricity supplied by PacifiCorp. PacifiCorp would provide a bill credit for net excess kWh generated by the net metered technology at a rate equivalent to the current rates set in Schedules 41 and PA-20, in Oregon and California, respectively. Natural gas-powered fuel cells are not eligible for net metering in California. Figure 6-12 provides an illustration of net metering for small generators.

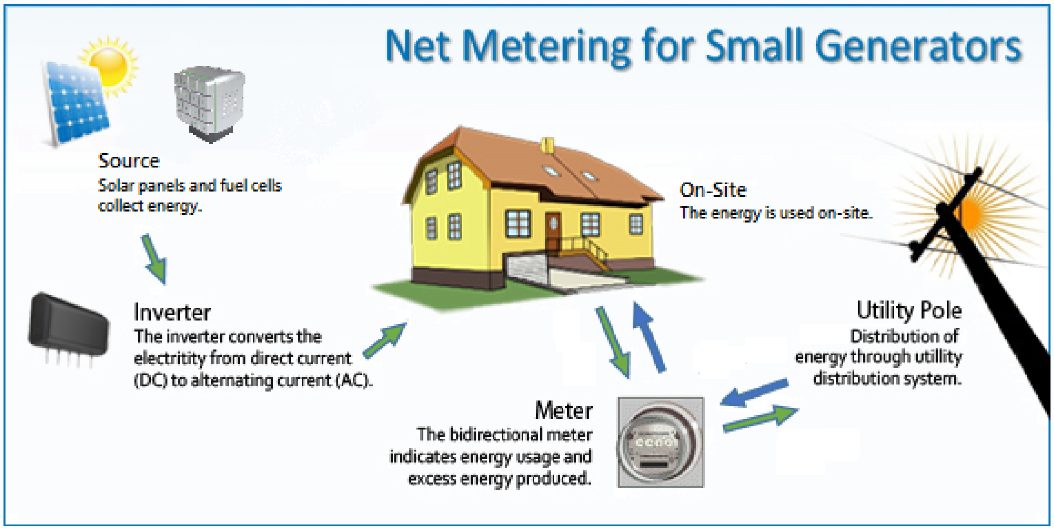


Figure 6-12. Illustration of Net Metering

To maximize the number of individual net metering opportunities, solar PV systems will be limited to a capacity of 5 kW and fuel cells to 8 kW. A 5-kW solar PV system would cost approximately $19,000, with an estimated cost of $3,800 per installed kW, and could fit on a typical residential or barn roof. An 8-kW fuel cell would cost roughly $20,000, with annual repayment of $1,149 over 25 years at three percent. Funding of $30 million could provide nearly 1,600 solar PV systems for over half of the Basin pumps.

Figure 6-13. Depiction of a Residential Sized Fuel Cell

Economic Benefits

- Solar PV systems are expected to produce about 8,400 kWh per year per system, offsetting $700 in Oregon and $900 in California per system based on current PacifiCorp rates in Schedules 41 and PA-20, respectively.

- Fuel cells are expected to produce approximately 49,000 kWh per year per system, offsetting about $3,300 in Oregon excluding fuel costs.

- The additional $10 million in KBRA funding could be used to pay down the fuel cell investment or the number and size of solar PV installations could be scaled up to provide panels to all pumps not net metered with fuel cells.

Other Benefits and Features

- Invests in the Basin economy through jobs.

- Offers a behind the meter option.

- Electricity produced is relatively clean and would reduce greenhouse gas emissions.

Uncertainties

- Number of net metered systems allowed per irrigator and specific sizing
- Avista infrastructure in Oregon to support fuel cells
- Funding mechanism for fuel cells
- Future price stability of natural gas

Potential Environmental Effects

There would be small footprint effects associated with the use of small-scale solar PV systems or natural gas-powered fuel cells. Conversion to net metering would reduce the carbon dioxide emissions associated with PacifiCorp's energy development portfolio.

Alternative Screening Evaluation

Alternative 8 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-21.

Table 6-21. Alternative 8 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ (Fair/Tolerable)	■ (Fair/Tolerable)	■ (Good)	■ (Good)	■ (Fair/Tolerable)	■ (Excellent)	■ (Excellent)	■ (Excellent)

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.9 Alternative 9: Demand Management

Alternative 9 adjusts irrigation operations to maximize access to PacifiCorp's time-of-use and load control programs. A funding pool would be established to build infrastructure, including water storage in the irrigation system and equipment modifications to facilitate district-level and on-farm time-of-use and load control operation. The funding pool would be managed by the future entity responsible for CAPP implementation (in the case of KBRA passage, the Klamath Basin Power Alliance [KBPA]) and would establish guidelines for project funding.

These demand management programs are generally more implementable on farms that are not reliant on scheduled water deliveries. Reported obstacles to demand management programs have included lack of labor, equipment sizing (many irrigation systems are sized to operate 24/7), and the need to take water when it is delivered. The funding pool would address any potential irrigation modifications that support time-of-use and load control programs.

Economic Benefits

- Time-of-use off-peak energy rate reduction would be 33 percent (from 9 ¢/kWh to 6 ¢/kWh) in Oregon and 38 percent (from 13 ¢/kWh to 8 ¢/kWh) in California.

- Load control can provide energy cost payments of $19/kW to $23/kW per year per pump. The load control program is available to loads greater than 50 kW, with the higher rates for loads over 100 kW. Average annual payment is projected at $1,475 to $2,025 based on PacifiCorp's load control program in Idaho and Utah.

Other Benefits and Features

- Optimizes the district and farm water delivery and storage systems to facilitate the time-of-use and load control programs.
- PacifiCorp would distribute economic benefits from load control programs on an annual basis for unused power during the designated shut down periods.
- Funding pool would be open to any irrigator or district for potential demand management measures.

Uncertainties

- Ultimate rates and conditions of PacifiCorp's Oregon time-of-use program based on pilot Schedule 215 and their proposed time-of-use program in California, which is currently before the California Public Utilities Commission (CPUC)
- Ultimate rates and conditions of PacifiCorp's load control program proposed in Oregon and California
- Degree of disruption to water deliveries in KID and Tulelake Irrigation District (TID) from large-scale time-of-use and load control programs
- The number of irrigators that could participate in PacifiCorp's time-of-use and load control programs

Potential Environmental Effects

On-farm water storage would generally have small footprint effects or no effects. Larger district level water storage could have moderate biological or social effects.

Example Demand Management Projects

Tulelake Sump 1-A Water Recirculation: Install pumps near the Tulelake Sump 1-A outfall to recirculate water into the J-1 Canal at Check 5 in order to reduce the pumping requirements of TID's Pumping Plant D. This option, also being considered as part of the On-Project Plan (OPP), is illustrated in Figure 6-14.

Figure 6-14. Project Depiction of Tulelake Sump 1-A Water Recirculation

Shasta View Irrigation District Water Storage: Install an estimated 10-million-gallon reservoir or pond that could be used to supply Shasta View Irrigation District (Shasta View ID) via gravity during times of peak energy rates. An identically-sized reservoir would be required near the Shasta View Intake Pumping Facility to allow Shasta View ID to continue diversion of scheduled water deliveries. Analysis of infrastructure and pumping costs at demand management rates is needed to understand economic viability. This example is depicted in Figure 6-15.

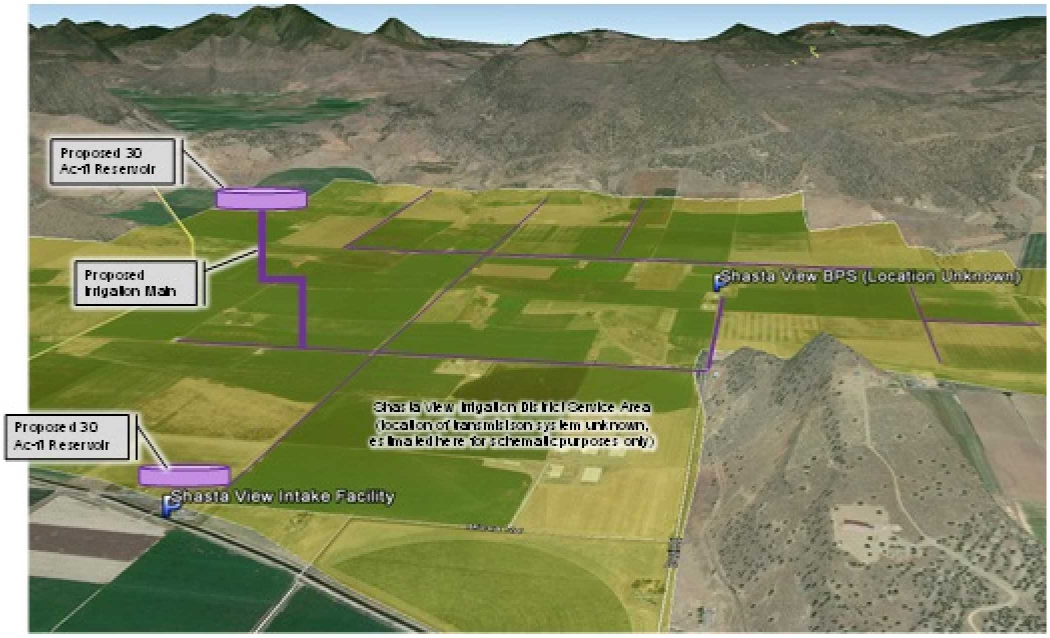


Figure 6-15. Example Reservoirs to Support Load Control in Shasta View ID

__On-Farm Storage Ponds:__ Install on-farm storage ponds to allow private irrigators to participate in the time-of-use or load control programs while still providing consistent flows out of district canals, as illustrated in Figure 6-16. These ponds would require a location where gravity filling could occur during the daily energy peak and a pump to drain the reservoir off-peak.

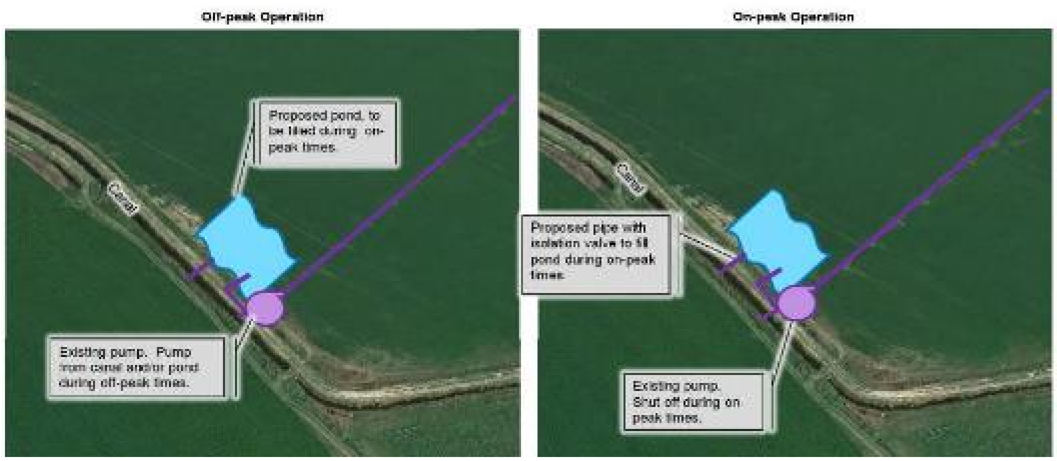


Figure 6-16. Project Depiction of On-Farm Storage Ponds

Alternative Screening Evaluation

Alternative 9 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-22.

Table 6-22. Alternative 9 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ Excellent	■ Fair/Tolerable	■ Good	■ Fair/Tolerable	■ Fair/Tolerable	■ Fair/Tolerable	■ Good	■ Good

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.10 Alternative 10: Revenue Stream and Efficiency

Alternative 10 would maximize district-level and on-farm efficiencies. The improvements to existing equipment to increase pump and motor efficiencies would leverage current PacifiCorp and Energy Trust programs. Efficiency would be coupled with a revenue stream that would be used to directly reduce energy costs through a bill credit.

Conceptually, a funding pool of unidentified value would be established with KBRA funding for pump and motor efficiency improvements including upgrades or replacements. In addition to private pumps, strategic equipment replacements that assist in maximizing energy savings would be undertaken at select Reserved and Transferred Works (R&T Works) facilities. The funding pool would be managed by the future entity responsible for CAPP implementation (in the case of KBRA passage, the KBPA), which would also establish guidelines for project funding.

Economic Benefits

- R&T Works upgrades save 65 to 81 million kWh annually, equivalent to approximately $60,000 to $80,000.
- Private pumps, both on-Project and off-Project, are projected to have total average annual energy savings of 7,000 kWh, or $700, at each pump.

Other Benefits and Features

- Funding would be pooled and open to any irrigator or district, but the distribution of benefits would be unequal because each facility is unique with regard to pump, farm, and district conditions.
- The potential for Federal power exists at Oregon R&T Works facilities.
- An incentive through the bill credit perpetually reduces energy use, i.e., greater energy savings result in a greater bill credit.
- The revenue stream would fund the KBPA.

Uncertainties

- Process for the equitable distribution of benefits due to highly variable costs for upgrading a pump or facility

- Ultimate management of the funding pool and measures for project selection

Potential Environmental Effects

Pump replacements at existing facilities would generally have small footprint effects or no effects.

Example Efficiency and Equipment Improvement Projects

Pumping Plant F and FF Equipment Replacement: This effort would replace Pumping Plant F and FF equipment with modern, properly-sized equipment and install variable frequency drives on three of the motors to match flows in the Klamath Straits Drain during low flow conditions. This is illustrated in Figure 6-17.

Figure 6-17. Project Depiction of Pumping Plant F and FF Equipment Replacement

Pumping Plant E and EE Reduced Equipment Capacity: Replace Pumping Plant EE equipment with modern, properly-sized equipment that matches the existing 105-cfs pumping capacity of each pump. Replace the three Pumping Plant E pumps with reduced capacity pumps to match the existing combined capacity of Pumping Plants E and EE (considering Pumps EE-3 and E-4 are currently offline) to match flows in the Klamath Straits Drain during low flow conditions. This option, also being considered as part of the OPP, is illustrated in Figure 6-18.

Figure 6-18. Project Depiction of Pumping Plant E and EE Reduced Capacity Equipment

Alternative Screening Evaluation

Alternative 10 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-23.

Table 6-23. Alternative 10 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	■ (Excellent)	■ (Excellent)	■ (Good)	■ (Fair/Tolerable)	■ (Fair/Tolerable)	■ (Excellent)	■ (Good)	■ (Good)

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.11 Alternative 11: Natural Gas Development

Alternative 11 is a natural gas only alternative and would capitalize on the availability of natural gas and certain advantages that natural gas motors offer over electrical motors. In some circumstances, gas engines are less expensive to operate and allow an operator to vary the motor speed and pump output to the specific irrigation condition. Engines also make it possible to operate an irrigation system 24 hours per day without regard for time-of-use. Net metered natural gas fuel cells in Oregon could provide economic advantages over a direct electrical connection.

Alternative 11 would systematically expand the Avista service territory and connections, including service in California. Electrical pumping equipment would be converted to natural gas over a time period consistent with the need to replace or upgrade electrical pumping equipment. Low efficiency electrical equipment would first be replaced with gas engines, then equipment would be retired from service over time. Newer electrical equipment would be retrofitted with net metered fuel cells in Oregon[5]. This alternative does not include running gas-driven generators to power electrical equipment.

Elements of this alternative include:

- Avista, the regulated gas utility in the Basin, would provide the irrigator with natural gas services.

- Avista would expand its service area by accessing the Pacific Connector natural gas pipeline scheduled for completion in 2017 to 2018.

- Most if not all irrigation pumps would take service from Avista's Schedule 420 for small commercial and industrial users at a rate of $1.08 per therm plus a monthly basic charge of $14.00 per meter.

- Pumps exceeding 50,000 therms (1.5 million kWh) annually would take Avista's Schedule 440 for large interruptible industrial users at a rate of $0.58/therm or Schedule 424 large industrial and commercial at a rate of $0.78/ therm. Pumps serviced under Schedule 440 that do not reach the 50,000 therm minimum would pay $0.12 per unused therm. Schedule 424 includes a monthly basic charge of $50.00 per meter.

Economic Benefits

- Engines become more cost competitive compared to electrical motors as the motor size and pumping increase because fuel efficiency increases with horsepower.

- Irrigators near existing fixed natural gas pipelines could take natural gas through Avista's Schedule 420 for small commercial and industrial users at

[5] Natural gas-powered fuel cells are ineligible for net metering in California.

the rate of $1.08 per therm. Under this schedule, a pump using 50,000 kWh (approximately 1,700 therms) would pay roughly $1,850. Neglecting all other costs, this would result in power cost savings of nearly 62 percent when compared to electrical power provided under PacifiCorp's Schedule 41.

- Net metered fuel cells in Oregon save an estimated 29 percent annually over direct electrical service when the fuel cell is appropriately sized.

- KBRA funding cannot be used for natural gas development, so a low interest loan and repayment schedule would be developed for the irrigation community through Reclamation or another financial mechanism. Providing a Federal low interest loan to the Off-Project irrigators would require Federal legislation.

- If time-of-use becomes the future default PacifiCorp schedule (as is the case in the Pacific Gas and Electric Company's agricultural service territory in California), gas could provide additional cost savings for full-time (24 hour) irrigation operations.

Other Benefits and Features

- The Jordan Cove-Pacific Connector Project is in development and is anticipated to extend to Malin, Oregon and connect to Avista's system near Shady Cove, Oregon providing an alternative natural gas supply to Avista (Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline no date). A connection to the Pacific Connector could expand Avista's service territory, but is not anticipated to change the rates that Avista currently charges as a regulated utility. Avista would remain the supplier of fixed natural gas to the Klamath Basin irrigators unless a separate bottle gas compressor plant is developed by a third party in the Basin.

- A natural gas transfer facility could be located near Malin, Oregon, providing compressed natural gas (CNG) from the Pacific Connector with retail sales through a third party. CNG would be distributed to remote well locations lacking fixed gas service.

- Investment in the Basin economy would occur through infrastructure and jobs.

- The effort would assist Oregon in meeting the Environmental Protection Agency's Clean Power Plan by reducing reliance on coal derived generation in PacifiCorp's generation portfolio.

Uncertainties

- Avista interconnection and natural gas costs from the Pacific Connector pipeline

- The costs for a new compressor plant and associated distribution infrastructure
- Fuel cell retail and installation costs
- Bottled natural gas retail price and supplier
- Ability of Avista to expand its territory into California
- Fuel cell future eligibility in California
- Avista's gas network in the Project and Off-Project areas, which is currently very limited in the rural areas; providing new gas supply lines to most pumps would be cost prohibitive
- Future price stability of natural gas

Potential Environmental Effects

Natural gas is cleaner than other forms of energy in PacifiCorp's generating portfolio. Conversion to natural gas could reduce reliance on more carbon dioxide-intense fuels like coal and may not result in a net increase in greenhouse gases. Systematic conversion of electrical pumps to natural gas would require the installation of substantial subsurface infrastructure with the potential to affect several biological and social resources, as well as air quality.

Alternative Screening Evaluation

Alternative 11 was assessed against the screening criteria and performance measures. The results of this evaluation are shown below in Table 6-24. Although a power cost savings of 62 percent (based only on power/fuel rates) can be realized with natural gas, Alternative 11 was assigned a poor rating for its ability to reduce rates/costs due to high infrastructure costs (new pumps and pipelines) which would not be eligible for KBRA funding.

Table 6-24. Alternative 11 Screening Evaluation

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Rating	Poor	Fair/Tolerable	Fair/Tolerable	Poor	Fair/Tolerable	Good	Poor	Fair/Tolerable

Legend: ■: Excellent ■: Good ■: Fair/Tolerable ■: Poor

6.2.12 Alternative 12: Regional Maximized Opportunity

Alternative 12 would maximize each region's ability to reduce power rates and/or costs by leveraging region-specific opportunities in the Oregon On-Project, Oregon Off-Project, and California On-Project areas. KBRA funding would be distributed on an equity basis between the three regions. For example, funds could be distributed on an energy use basis where the Oregon On-Project, Oregon Off-Project, and California On-Project areas would receive 44, 37, and 19 percent of the funds, respectively. A formula for fund distribution would be developed by the future CAPP Management Entity.

Specific opportunities in these regions are already described in the other alternatives and are listed here for reference. Alternative 12 is primarily focused on the concept of each region determining the opportunities that serves it best. With the exception of low-head hydro, the revenue generation options are not discussed as they can, for the most part, be developed equally in each region.

6.2.12.1 Oregon On-Project Opportunities

Potential opportunities in the Oregon On-Project area include:

- Klamath Straits Drain flow to Lower Klamath National Wildlife Refuge recirculates water in the Project instead of pumping the water out through the Klamath Straights Drain to the Klamath River as defined in the OPP. This option reduces pumping at Pumping Plants D, F, and FF.
- Federal power could be provided to select large R&T Works.
- Low-head hydro could be provided at A Canal and G Canal as defined in Alternative 2.
- Redirect TID Water Diversions at Station 48 to A Canal, increasing flow through the KID Canal C powerhouse. Water would then be released to the Lost River from Canal C for recovery by TID.
- Efficiency and net metering provide the greatest opportunity to reduce power costs and rates.

6.2.12.2 Oregon Off-Project Opportunities

Specific opportunities offered to the Oregon Off-Project area include:

- Efficiency and net metering provide the greatest opportunity to reduce power costs and rates.
- Load control and time-of-use programs are highly implementable due to high reliance on groundwater pumping and surface stream diversion, which do not rely on scheduled irrigation deliveries.

6.2.12.3 California On-Project Opportunities

Opportunities offered to the California On-Project area include:

- Tulelake Sump 1-A Recirculation of water into the J-1 Canal at Check 5 to reduce pumping at D Plant could be implemented as described in the OPP.

- Strategic location of wells in the OPP area reduces pumping costs by strategically locating wells in areas where the groundwater table is higher.

- Efficiency and net metering provide the greatest opportunity to reduce power costs and rates.

6.3 Alternatives Screening Evaluation

The preliminary alternatives were assessed against the screening criteria and performance measures. The results of this evaluation are shown in Table 6-25.

Table 6-25. Summary of Preliminary Alternative Screening Analysis

	Consistency with the KBRA	Consistency with Regulations and Policies	Access to Benefits	Distribution of Benefits	Admin. Intensity	Durability	Ability to Reduce Rates/Costs	Potential Env. Effects
Alternative 1: Utility-Scale Solar	🟩	🟩	🟩	🟩	🟦	🟩	⬛	⬛
Alternative 2: Low-head Hydro Options								
Hydro at Keno Dam	🟩	🟦	🟦	🟦	🟦	🟦	⬛	⬛
Hydro at Westside Powerhouse, and Eastside Powerhouse	🟩	🟩	🟦	🟦	🟦	🟦	⬛	⬛
Hydro at Eastside Powerhouse with A Canal Water, A Canal, and G Canal	🟩	🟩	🟦	🟦	🟦	🟩	⬛	🟦
Alternative 3: Out-of-Basin Investment	🟩	🟩	🟩	🟩	🟦	🟦	🟦	🟩
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	🟩	🟩	🟩	🟩	🟦	🟩	🟦	🟦
Alternative 5: Geothermal	🟩	🟩	🟩	🟩	⬛	🟩	🟥	🟦
Alternative 6: Shared Solar	🟩	🟥	🟩	🟩	⬛	🟦	🟦	🟦
Alternative 7: Utility-Scale and Net Metered Solar	🟩	🟩	🟩	🟩	🟦	🟩	🟦	🟦
Alternative 8: Net Metering	⬛	⬛	🟦	🟦	⬛	🟩	🟩	🟩
Alternative 9: Demand Management	🟩	⬛	🟦	⬛	⬛	⬛	🟦	🟦
Alternative 10: Revenue Stream and Efficiency	🟩	🟩	🟦	⬛	⬛	🟩	🟦	🟦
Alternative 11: Natural Gas	🟥	⬛	⬛	🟥	⬛	🟦	🟥	⬛

Legend: 🟩: Excellent 🟦: Good ⬛: Fair/Tolerable 🟥: Poor

Overall, Alternatives 1, 3, 4, and 7 perform well against all screening criteria. Alternatives 1, 4, and 7 could be improved with a PPA that provides a purchase price greater than the avoided cost for power. All variations of low-head hydro for Alternative 2 have uncertainties regarding the final design and operations necessary to accommodate sucker and salmon.

Alternative 5 requires a large capital investment with an uncertain financial return for geothermal development. The well field development costs could be substantially greater than projected, reducing the net benefits of this technology. Existing Basin geothermal developers are not interested in additional financial partners.

Alternative 6 performs well against all screening criteria except the large uncertainty of developing the necessary regulatory policies. Alternative 8, Net Metering, has the greatest potential to lower energy rates behind the meter. A formula and administrative process would need to be derived to equitability distribute the solar versus fuel cell benefits. This alternative is challenged by the inconsistencies associated with net metering fuel cells in California and Oregon.

Alternative 9 would be challenged to equitably distribute benefits to all irrigators, and none of the programs have final approval from CPUC or Oregon Public Utility Commission. Managing a funding pool for demand management projects would require a large administrative effort that would likely increase proportionally as funding equity to every irrigator is achieved.

Alternative 10 would be challenged to equitably distribute benefits to all irrigators. Managing a funding pool for efficiency and improvement projects would require a large administrative effort that would likely increase proportionally as funding equity to every irrigator is achieved.

Alternative 11 is challenged by the lack of Avista infrastructure to supply gas to irrigation pumps in California and Oregon, uncertainties with the Pacific Connector interconnection, and different regulations for fuel cell net metering in both states. This alternative would also be challenged to equitably distribute benefits to all irrigators. Large scale conversion of irrigation equipment to natural gas would require a focused long-term administrative commitment without defined funding.

Alternative 12 was not assessed against the screening criteria and performance measures that were developed to evaluate CAPP options and alternatives. This alternative would advance if the Technical Workgroup determines that the best way to distribute the benefits from the KBRA would be allocating funds to the three regions.

6.4 Alternatives Ranking

In response to the proceedings of TWG-5, held in early June 2015, the technical team developed and distributed an alternative ranking poll to the TWG to assess their support for the initial CAPP alternatives and to establish a preliminary ranking of the alternatives for the Draft Initial Alternatives Information Report (IAIR). A list of uncertainties associated with each alternative and an updated summary of the results of the alternative screening evaluation were provided along with the ranking request to assist with the completion of the poll. The alternatives screening evaluation was updated to include suggestions made during TWG-5 to reevaluate each alternative based on its ability to lower irrigator energy rates and distribute benefits equitably.

The poll used the "gradient of agreement" concept to gauge individual stances on each alternative, as shown in Figure 6-19. This scale provides a simple method for scoring alternatives. An alternative score was determined by factoring in the number of votes and grade (1 through 5) of votes for the alternative. For example, if two voters chose to endorse an alternative and three indicated mixed feelings, the resulting score would be two (voters) multiplied by one (grade) plus three (voters) multiplied by three (grade) for a total of 11. Alternatives were then ranked from best to worst, where the best alternative received the lowest score. Alternatives were then separated into three tiers representing the highest, moderate, and low ranking alternatives.

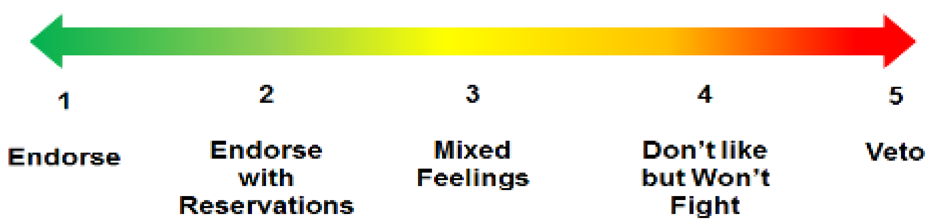


Figure 6-19. Gradient of Agreement for Alternatives Rating

Individual responses were collected and divided into two groups: 1) irrigators and agencies serving or representing irrigators, and 2) outside policy reviewers. The technical team received nine responses; six were from irrigators or those who reside with an organization representing or serving the irrigation community and three represented power policy. Poll results from these two groups are shown in Tables 6-26 and 6-27. ,e irrigation group favored Alternative 3, Out-of-Basin Investment, while outside policy representatives favored Alternative 6, Shared Solar and Alternative 7, Utility-Scale and Net Metered Solar. Collectively, the two groups scored Alternative 11, Natural Gas and Alternative 5, Geothermal unfavorably.

Table 6-26. Poll Results from Irrigators and Agencies Serving or Representing Irrigators

Alternative	1. Endorse	2. Endorse with Reservations	3. Mixed Feelings	4. Don't like, Won't Fight	5. Don't Like	Score
Alternative 3: Out-of-Basin Investment	4	1	0	1	0	10
Alternative 10: Revenue Stream and Efficiency	4	0	0	2	0	12
Alternative 7: All Solar	2	2	1	1	0	13
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	1	4	0	1	0	13
Alternative 6: Shared Solar	1	3	2	0	0	13
Alternative 1: Utility-Scale Solar	0	3	3	0	0	15
Alternative 8: Net Metering	0	3	3	0	0	15
Alternative 2: Low-Head Hydro	0	1	4	1	0	18
Alternative 9: Demand Management	0	3	1	0	2	19
Alternative 12: Regional Maximized Opportunity	2	0	0	2	2	20
Alternative 11: Natural Gas	0	0	1	3	2	25
Alternative 5: Geothermal	0	0	0	4	2	26

Table 6-27. Poll Results from Outside Policy Reviewers

Alternative	1. Endorse	2. Endorse with Reservations	3. Mixed Feelings	4. Don't like, Won't Fight	5. Don't Like	Score
Alternative 6: Shared Solar	3	0	0	0	0	3
Alternative 7: All Solar	3	0	0	0	0	3
Alternative 9: Demand Management	2	0	1	0	0	5
Alternative 8: Net Metering	1	1	1	0	0	6
Alternative 10: Revenue Stream and Efficiency	1	1	1	0	0	6
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	1	0	2	0	0	7
Alternative 1: Utility-Scale Solar	1	1	0	0	1	8
Alternative 2: Low-Head Hydro	1	1	0	0	1	8
Alternative 12: Regional Maximized Opportunity	1	0	1	1	0	8
Alternative 3: Out-of-Basin Investment	1	0	1	1	0	8
Alternative 5: Geothermal	0	0	1	0	2	13
Alternative 11: Natural Gas	0	0	1	0	2	13

Table 6-28 provides the combined results, which are organized into three tiers (best to worst). Based on the collective results, the technical team recommends further economic and technical analysis on the Tier 1 and 2 alternatives prior to selecting the alternatives for the Final Alternative Report (FAR).

Table 6-28. Poll Results Based on All Respondents

Alternative	1. Endorse	2. Endorse with Reservations	3. Mixed Feelings	4. Don't like, but Won't Fight	5. Don't Like	Score
Tier 1						
Alternative 7: All Solar	5	2	1	1	0	16
Alternative 6: Shared Solar	4	3	2	0	0	16
Alternative 3: Out-of-Basin Investment	5	1	1	2	0	18
Alternative 10: Revenue Stream and Efficiency	5	1	1	2	0	18
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	2	4	2	1	0	20
Tier 2						
Alternative 8: Net Metering	1	4	4	0	0	21
Alternative 1: Utility-Scale Solar	1	4	3	0	1	23
Alternative 9: Demand Management	2	3	2	0	2	24
Alternative 2: Low-Head Hydro	1	2	4	1	1	26
Tier 3						
Alternative 12: Regional Maximized Opportunity	3	0	1	3	2	28
Alt 11: Natural Gas	0	0	2	3	4	38
Alt 5: Geothermal	0	0	1	4	4	39

Technical Workgroup Meeting #5

TWG-5 was held on June 10, 2015 in the Klamath Water and Power Agency/Klamath Water Users Association conference room in Klamath Falls, Oregon. A webinar was held simultaneously for those who could not attend in person.

Purpose

The purpose of this meeting was to present the proposed alternatives for the IAIR, brainstorm any revisions to the alternatives, and identify the process and decision makers for finalizing the alternatives.

Major Outcomes and Decisions

The TWG reviewed and provided comments on each of the alternatives. The general group consensus was that alternatives should be ranked with the ability to lower costs most heavily weighted, followed by the ability to distribute benefits. It was expressed that an alternative's consistency with the KBRA or regulatory policies was not to be used as a pass/fail or weighted more heavily than other criteria.

The technical team recommended that the alternatives be ranked and subsequently put into tiers to be carried throughout the IAIR and FAR documents. This process would allow several alternatives to advance, but would not require the same level of engineering and financial analysis for all. There was no consensus on the final decision makers for the alternatives; however, it was proposed that the Klamath Basin Power Alliance serve in this role.

Due to timing limitations, the TWG was unable to rank alternatives. As a result, the technical team developed an alternatives ranking poll using the "gradients of agreement" concept to gauge the level of TWG acceptance for each alternative. This poll was conducted electronically during the week following TWG-5. Individual responses were collected and are summarized in Section 6.4.

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Chapter 7
Final IAIR Alternatives Ranking

Following initial alternatives development and screening, additional economic analysis was performed on many of the top ranked alternatives to understand the alternatives' ability to reduce power costs using updated PacifiCorp avoided cost prices for the purchase of Public Utility Regulatory Policy Act (PURPA) power. This chapter presents the results of the additional economic analysis as well as new information on biomass power development provided by the Klamath Tribes and updates from PacifiCorp on power development in the Basin.

7.1 Revised Economic Analysis

Each CAPP alternative has the ability to lower power costs for individual Basin irrigators, either by lowering delivered energy rates received from the local utility or by lowering the overall power cost by affecting another component of the energy use equation. For example, delivered energy rates can be lowered through time-of-use metering, with power rates varying based on the time of day the power is used. Power costs can be lowered by providing a dividend to individual irrigators from the power generated off-site and sold to a utility.

The previous analysis provided simplistic economic analysis on the first year of project operation, using an average avoided cost provided in PacifiCorp's Schedule 37. Further economic analysis was undertaken to provide an in-depth representation of project revenue and associated economic benefits. This section provides a description of the economic analysis performed subsequent to the fifth technical workgroup meeting (TWG-5) where top ranked alternatives were identified.

7.1.1 Assumptions

Table 7-1 lists assumptions specific to evaluated alternatives. Common assumptions for the analysis included the following:

- PURPA Qualifying Facilities would sell power to PacifiCorp at their avoided cost.
- Estimated costs and revenues do not include land purchase, permitting, or interconnection.
- The annual baseline energy use provided in Table 4-1 remains constant throughout the multi-year analysis.

- On- and off-peak hours and the number of North American Electric Reliability Corporation holidays, as provided in Schedule 37, remain constant throughout the multi-year analysis.
- Energy rates in Schedules 41 and PA-20 escalate at the same rate as the avoided cost prices provided in Schedule 37.
- Assumed inflation rates remain constant throughout the multi-year analysis (a general rate of 5 percent and 4.7 percent for PURPA projects).

Table 7-1. List of Alternative-Specific Assumptions

Alternative	Assumption
Alternative 3: Out-of-Basin Investment	• Yieldco annual yield remains constant through 2041 • The principal remains invested throughout
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	• Klamath Basin Restoration Agreement (KBRA) funding would be divided equally between utility-scale development and out-of-Basin investments • Yieldco annual yield remains constant through 2041 • The principal remains invested throughout
Alternative 6: Shared Solar	• All generated power offsets power delivered by PacifiCorp at the full energy rates in Schedules 41 and PA-20
Alternative 7: Utility-Scale and Net Metered Solar	• KBRA funding would be divided equally between utility-scale development and net metered solar installations • All generated power offsets power delivered by PacifiCorp at the full energy rates in Schedules 41 and PA-20 • No annual excess generation is produced by net metered installations
Alternative 8: Net Metering (Solar PV and Fuel Cells)	• KBRA funding would be divided between Oregon and California on an energy use basis • Fuel cells are ineligible in California • Natural gas service is available for fuel cells • Fuel cells are run 24 hours per day • All generated power offsets power delivered by PacifiCorp at the full energy rates in Schedules 41 and PA-20 • No annual excess generation is produced by net metered installations

7.1.2 Power Rate Reduction

Rate reduction percentages for CAPP alternatives were calculated separately for Oregon and California, where possible. Economic benefits were allocated to Oregon and California on an energy use basis (roughly 81 percent Oregon, 19 percent California), based on the annual baseline energy use provided in Table 4-1. Alternatives resulting in the generation of revenue would distribute the revenue to Basin irrigators on a kilowatt-hour (kWh) pro-rata basis, and would be applied equally across all PacifiCorp Schedule 41 and PA-20 users through a direct energy credit on individual power bills.

Rate reduction percentages for each state were determined by subtracting the annual gross revenue or value of offset energy from the current energy cost, dividing it by the annual energy demand, and then determining the percent difference between this new rate and the current energy rates provided in PacifiCorp's Schedules 41 and PA-20. An example of this rate reduction calculation is provided in the textbox to the right.

Example Rate Reduction Calculation

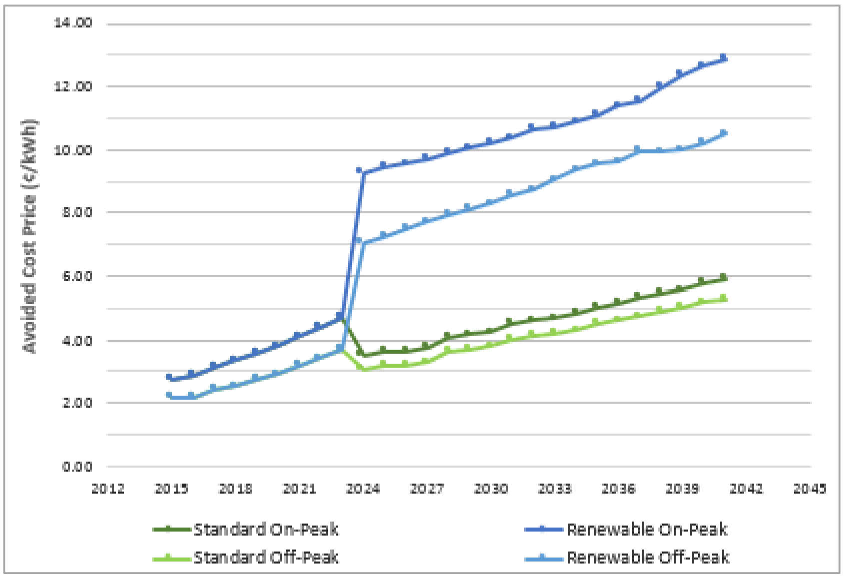
Presume that in 2015 a $40 million investment is used to build a 15,400-kilowatt (kW) utility-scale solar project capable of producing approximately 40.4 million kWh annually. Irrigators would still purchase all energy needed through PacifiCorp under their scheduled rates, which for Oregon Schedule 41 users is 9.674 ¢/kWh. Oregon irrigators' annual energy use is 96 million kWh. Multiplying the energy use by the energy rate results in a total cost of $9.3 million. Now presume that the operation and maintenance of the solar project costs $27/kW, or $416,000. Since the Oregon irrigators account for 81 percent of the Basin energy use, their share of the O&M costs would be about $337,000. If the energy from the solar project is sold at PacifiCorp's averaged avoided cost of 2.68 ¢/kWh, the Oregon irrigators' share of those sales would be $877,000 ($.0268/kWh * 40,400,000 kWh * 0.81). Therefore, the net cost of electricity for the Oregon irrigators is $9.3 million plus $337,000 less $877,000, or $8,760,000. Dividing this net cost by the total Oregon irrigators' electricity use of 96 million kWh results in an average cost of 9.13¢/kWh. The percent difference between this rate and the Schedule 41 rate of 9.674 ¢/kWh is 6 percent ((9.674-9.13)/9.674).

This analysis projected annual revenue and rate reduction estimates for each of the evaluated alternatives over the first 27 years of operation. Figure 7-1 presents the avoided cost prices for purchases from Qualifying Facilities through 2041, a 27-year forecast, as provided in PacifiCorp's Schedule 37. Projections for alternatives that would sell power to PacifiCorp include inflationary adjustments on Schedule 41 and PA-20 energy rates using the calculated average annual inflation rate of 4.7 percent, based on the avoided cost prices and definitions of on- and off-peak hours provided in Schedule 37. This average annual inflation rate was calculated by averaging the inflation rates calculated for on- and off-peak prices from 2015 to 2041, with on-peak prices weighted at 84 percent and off-peak prices at 16 percent. General inflationary adjustments using a five percent inflation rate were applied to operation and maintenance costs, as well as Schedule 41 and PA-20 energy rates for alternatives that would not sell power to PacifiCorp.

Revenue and rate reduction projections for renewable energy generation were provided using both the Standard and Renewable Fixed Avoided Cost Prices provided in Schedule 37. It is uncertain whether solar projects will qualify for Renewable Fixed Avoided Cost Prices as PacifiCorp is actively attempting to complete projects to fulfill the Solar Photovoltaic Capacity Standard set in Oregon Administrative Rule 860-084-0020, and has stated it is unlikely that capacity will remain available for CAPP projects (PacifiCorp 2015b). Schedule 37 provides the following for Standard and Renewable pricing options:

- Standard Fixed Avoided Cost Prices are available to all Qualifying Facilities.

- Renewable Fixed Avoided Cost Prices are available only to Renewable Qualifying Facilities, Qualifying Facilities that generate electricity that meets the requirements set forth in the Oregon Renewable Portfolio Standards: Oregon Revised Statute 469A.010, 469A.020, and 469A.025. Renewable Qualifying Facilities that choose Renewable Fixed Avoided Cost pricing must cede all Green Tags generated by the facility to PacifiCorp.



Source: PacifiCorp 2015c

Figure 7-1. Comparison of PacifiCorp's Avoided Cost Prices 2015-2041

7.1.3 Summary of Results

Revenue and rate reductions associated with the first operational year (2015) of each alternative are provided in Table 7-2. The full evaluation of each applicable CAPP alternative can be found in Appendix E, Klamath CAPP Alternatives Economic Analysis.

Table 7-2. Summary of Alternatives Economic Evaluation – First Year of Operation

Revenue Generating Alternative	Annual Net Revenue[1]	Rate Reduction Oregon[1]	Rate Reduction California[1]
Alternative 1: Utility-Scale Solar	$667,000/	5.8%	4.4%
Alternative 2: Low-Head Hydro Options			
Hydro at Keno Dam	$575,000	5.0%	3.8%
Hydro at Westside Powerhouse	$80,000	0.7%	0.5%
Hydro at Eastside Powerhouse	$308,000	2.7%	2.0%
Hydro at Eastside Powerhouse with A Canal Water	$224,000	2.0%	1.5%
Hydro at A Canal	$95,000	0.8%	0.6%
Hydro at G Canal	$27,000	0.2%	0.2%
Alternative 3: Out-of-Basin investment	$1.6 million	14.0%	10.5%
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	$1.1 million	9.9%	7.4%
Alternative 5: Geothermal[2]	-$44,000	-0.4%	-0.3%
Alternative 6: Shared Solar	$2.6 million	23.1%	17.2%
Alternative 7: Utility-Scale and Net Metered Solar	$1.5 million	13.0%	11.6%
Alternative 8: Net Metering	$2.1 million	18.4%	12.8%
Alternative 11: Natural Gas Development	NA	NA	NA
Alternative 12: Regional Maximized Opportunity	NA	NA	NA
Efficiency and Demand Management Options[3]			
Time of Use	$1,550 - $2,080	32.7%	32.9%
Load Control	$900	19.0%	14.2%
Time of Use and Load Control	$2,450 - $2,990	51.7%	47.1%
Efficiency Improvements[4]	$710 - $950	15.0%	15.0%

[1] Standard and Renewable Fixed Avoided Cost prices are identical from 2015 to 2023, resulting in identical revenue and rate reductions during this period.

[2] A well field cost was applied to the first year of geothermal energy production, resulting in zero rate reductions. Reductions in the second year, 2016, were estimated at 3.7 percent in Oregon and 2.8 percent California.

[3] Represents savings for the average individual Basin irrigator using around 49,000 kWh (43 kW) annually. It is uncertain how many irrigators could be supported under these programs.

[4] Assumes efficiency improvements result in 15 percent reduction in energy use.

[NA] No additional analysis was performed

Table 7-3 provides the estimated revenue and rate reductions for Alternative 1, Utility-Scale Solar, with Standard and Renewable Fixed Avoided Cost prices for years 2015 through 2041. These rates could apply to alternatives with solar PV and hydroelectric (hydro) power development. A critical factor in the economic analysis is whether renewable generation projects will qualify for Renewable Fixed Avoided Cost pricing. As shown in Table 7-3, starting in 2024, power generated by Renewable Qualifying Facilities under the renewable pricing option provided substantially greater rates and consequently higher rate reductions than those with the standard pricing option. For comparative purposes, PacifiCorp recently signed a power purchase agreement with Ewauna Solar, LLC with rates different than those shown in Schedule 37. A summary of this project is provided in the textbox.

Table 7-3. Projected Performance of Alternative 1 – Utility-Scale Solar

Year	Annual Net Revenue[1]	Rate Reduction Oregon[1]	Rate Reduction California[1]	Annual Net Revenue[2]	Rate Reduction Oregon[2]	Rate Reduction California[2]
2015	$667,000	5.8%	4.4%	$667,000	5.8%	4.4%
2016	$681,000	5.7%	4.3%	$681,000	5.7%	4.3%
2017	$762,000	6.1%	4.5%	$762,000	6.1%	4.5%
2018	$831,000	6.4%	4.7%	$831,000	6.4%	4.7%
2019	$877,000	6.4%	4.8%	$877,000	6.4%	4.8%
2020	$957,000	6.7%	5.0%	$957,000	6.7%	5.0%
2021	$1,045,000	7.0%	5.2%	$1,045,000	7.0%	5.2%
2022	$1,136,000	7.2%	5.4%	$1,136,000	7.2%	5.4%
2023	$1,228,000	7.5%	5.6%	$1,228,000	7.5%	5.6%
2024	$735,000	4.3%	3.2%	$2,963,000	17.2%	12.8%
2025	$755, 000	4.2%	3.1%	$3,005,000	16.7%	12.4%
2026	$725,000	3.8%	2.9%	$3,022,000	16.0%	11.9%
2027	$745,000	3.8%	2.8%	$3,057,000	15.5%	11.5%
2028	$832,000	4.0%	3.0%	$3,094,000	15.0%	11.2%
2029	$837,000	3.9%	2.9%	$3,122,000	14.4%	10.8%
2030	$832,000	3.7%	2.7%	$3,152,000	13.9%	10.4%
2031	$889,000	3.7%	2.8%	$3,171,000	13.4%	10.0%
2032	$892,000	3.6%	2.7%	$3,221,000	13.0%	9.7%
2033	$872,000	3.4%	2.5%	$3,233,000	12.4%	9.3%
2034	$882,000	3.2%	2.4%	$3,251,000	11.9%	8.9%
2035	$901,000	3.2%	2.4%	$3,289,000	11.5%	8.6%
2036	$894,000	3.0%	2.2%	$3,345,000	11.2%	8.4%
2037	$896,000	2.9%	2.1%	$3,356,000	10.7%	8.0%
2038	$899,000	2.8%	2.1%	$3,443,000	10.5%	7.9%
2039	$883,000	2.6%	1.9%	$3,512,000	10.3%	7.7%
2040	$892,000	2.5%	1.9%	$3,551,000	9.9%	7.4%
2041	$870,000	2.3%	1.7%	$3,567,000	9.5%	7.1%

[1] Values derived from Standard Fixed Avoided Cost prices.

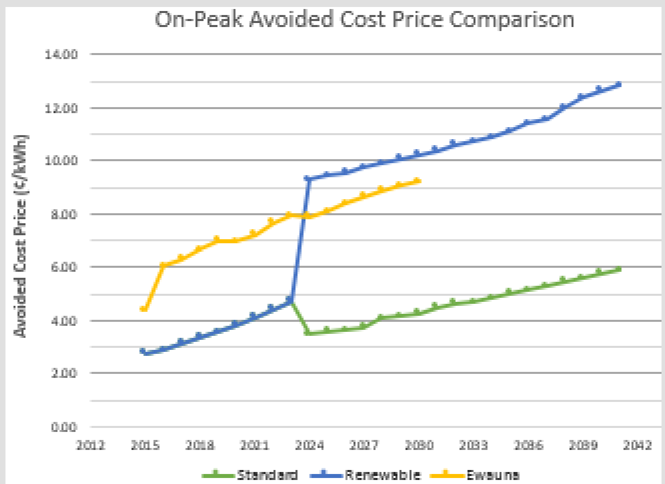
[2] Values derived from Renewable Fixed Avoided Cost prices.

NOTE: A cost shift occurs from 2023 to 2024, during which Standard on-peak prices increase by approximately 23 percent and off-peak prices decrease by roughly 21 percent. Renewable prices increase by approximately 61 percent on-peak, and 48 percent off-peak.

Example Solar Project in the Klamath Basin

In March 2015, Ewauna Solar, LLC signed a power purchase agreement with PacifiCorp for an 830-kW Qualifying Facility in Klamath Falls, Oregon. This project would generate, on average, 1,850,000 kWh of solar photovoltaic energy annually. Power generated at this facility is sold to PacifiCorp at the avoided cost prices shown in the table below. A comparison of the avoided cost prices awarded to Ewauna Solar, LLC and those provided in the latest revision of PacifiCorp's Schedule 37 is shown in the figure below. As shown, purchase pricing for the Ewauna Solar, LLC project is more favorable than the Standard Fixed pricing rates, and does not experience a major cost shift in 2024 as do the Standard and Renewable Fixed prices. It appears that the avoided cost prices for Ewauna Solar, LLC splits the difference between the beginning and end pricing, with (higher rates awarded in the earlier years and lower rates in later years).

Delivery Year	On-Peak Price (¢/kWh)	Off-Peak Price (¢/kWh)
2015	4.39	2.99
2016	6.04	3.69
2017	6.32	3.91
2018	6.66	4.21
2019	6.99	4.5
2020	6.94	4.41
2021	7.23	4.65
2022	7.67	5.04
2023	7.92	5.24
2024	7.89	5.16
2025	8.09	5.32
2026	8.39	5.57
2027	8.66	5.78
2028	8.88	5.95
2029	9.07	6.09
2030	9.2	6.16



Source: Ewauna Solar, LLC Power Purchase Agreement 2015, PacifiCorp 2015c

7.2 Biomass Power Development

The Power for Water Management section of the KBRA specifies that the Financial and Engineering Plan study the technical and economic viability of the Klamath Tribes' biomass program. Biomass was removed from the CAPP options formulation process during the fourth technical workgroup meeting due to its high levelized cost of energy (LCOE) relative to other power generation options. The high LCOEs of forest product-based biomass power development are generally reflective of the high cost to purchase, gather, and transport the biomass feedstock. The CAPP technical team met with the Klamath Tribes in August 2015 about the Tribes' biomass program. The Tribes are studying a number of potential feedstock programs on National Forest land and private property on or in the vicinity of former Tribal lands that could provide less expensive feedstock, potentially making biomass competitive with other power development options (J. Hall, personal communication, August 26, 2015). Biomass power development was therefore reintroduced as an alternative so that any new information developed by the Tribes during the FAR evaluation could be compared against other power development alternatives.

Technical Workgroup Meeting #6

TWG-6 was held on August 27, 2015 in the Klamath Water and Power Agency/Klamath Water Users Association conference room in Klamath Falls, Oregon. A webinar was held simultaneously for those who could not attend in person.

Purpose
The purpose of this meeting was to discuss the Draft IAIR, present the results of the revised economic analysis, and list the study elements for the FAR.

Major Outcomes and Decisions
The TWG reviewed and provided comments on each of the alternatives included in the Draft IAIR. Concern was expressed for the feasibility of hydro options on the Link River, as environmental impacts and overall costs remain highly variable and uncertain. The equitable distribution of benefits from the demand management and efficiency alternatives were expressed, as it is unclear how irrigators that have already implemented the programs would benefit.

The TWG decided that biomass power development should be reintroduced as Alternative 13 and carried forward to the FAR, based on the new information received from the Klamath Tribes on August 26, 2015 on their biofuel and biomass power development ventures in the Klamath Basin. This alternative was placed in Tier 2 for further engineering and economic analysis.

The general group consensus was that Alternative 2's Eastside Powerhouse option be moved down into Tier 3 and Alternative 12, Regional Maximized Opportunities be moved up into Tier 2. The group agreed that further engineering and economic analysis be provided in the FAR for Tiers 1 and 2, while alternatives in Tier 3 should be carried through without further analysis.

7.3 Revised Alternatives Ranking

Alternatives were organized into three tiers (best to worst) based on the feedback provided by members of the technical workgroup during TWG-5, which consisted of irrigators, agencies serving or representing irrigators, and outside policy reviewers. Feedback was based on the "gradient of agreement" concept, as discussed in Section 6.4. Table 6-28 provides the results of the alternatives ranking conducted during TWG-5. Following the TWG-5 ranking, further economic analysis was conducted on the top-tier alternatives and the alternatives were discussed during the sixth TWG meeting (TWG-6). A revised alternative ranking was conducted as shown in Table 7-4. At the time of this analysis, it was uncertain whether PacifiCorp would enter into a power purchase agreement for CAPP power development projects at the renewable fixed rates, so the standard rates were used (see Section 7.1.2.1).

The primary differences between the TWG-5 and TWG-6 rankings (Tables 6-28 and 7-4, respectively) are as follows:

- Five of the six options in Alternative 2, Low-Head Hydro, were moved down from Tier 2 into Tier 3 after additional economic analysis determined the projects were not economically feasible. PacifiCorp confirmed that the acquisition of Eastside and Westside powerhouses from PacifiCorp will require approval from the Oregon Public Utility Commission, as it is an asset valued in excess of $100,000. PacifiCorp must file notifications that the facilities would be transferred and provide proof that the transaction is in the public interest and beneficial to the public. It is likely that competitive bidding would be employed to establish a fair market value of the facilities (PacifiCorp 2015b). The five options moved to Tier 3 were hydro at Eastside Powerhouse, hydro at Eastside Powerhouse with A Canal Water, hydro at Westside Powerhouse, hydro at A Canal, and hydro at G Canal.
- Alternative 8, Net Metering, was moved up from Tier 2 into Tier 1. However, PacifiCorp is currently participating in a regulatory docket in Oregon (“the Value of Solar Docket”) focused on the value of solar energy to the utility and customers. It remains unknown whether this will result in modifications or limitations to the existing net metering programs in Oregon (PacifiCorp 2015b).
- Alternative 10, Revenue Stream and Efficiency, was moved down from Tier 1 into Tier 2.
- Alternative 13, Biomass Power Development was reintroduced and placed into Tier 2.

Tier 1 presents the best opportunities while Tier 2 provides opportunities that have promise but may contain implementation obstacles or provide a lower potential for reducing rates. Tier 3 represents alternatives that do not reduce rates, or contain substantial uncertainties. Tier 1 and 2 alternatives will be further analyzed in the Final Alternatives Report (FAR) analysis.

Table 7-4. Revised Alternatives Ranking

Alternative	Average Rate Reduction[1] Oregon	Average Rate Reduction[1] California
Tier 1		
Alternative 7: Utility-Scale and Net Metered Solar	9.7%	9.1%
Alternative 6: Shared Solar	23.1%	17.2%
Alternative 3: Out-of-Basin Investment	8.0%	6.0%
Alternative 4: Utility-Scale Solar and Out-of-Basin Investment	6.3%	4.7%
Alternative 8: Net Metering	19.4%	12.8%
Tier 2		
Alternative 1: Utility-Scale Solar	4.3%	3.2%
Alternative 10: Revenue Stream and Efficiency[2]	up to 15%	up to 15%
Alternative 9: Demand Management[2]	up to 51.7%	up to 47.1%
Alternative 2: Hydro at Keno Dam	5.6%	4.2%
Alternative 13: Biofuels and Biomass Power Development	NA	NA
Alternative 12: Regional Maximized Opportunity	NA	NA
Tier 3		
Alternative 2: Hydro at Eastside Powerhouse	3.0%	2.2%
Alternative 2: Hydro at Eastside Powerhouse with A Canal Water	2.2%	1.6%
Alternative 2: Hydro at A Canal	0.9%	0.7%
Alternative 2: Hydro at Westside Powerhouse	0.8%	0.6%
Alternative 2: Hydro at G Canal	0.3%	0.2%
Alternative 11: Natural Gas Development	NA	NA
Alternative 5: Geothermal	4.6%	3.4%

[1] The values shown here represent the average rate reduction percentage from 2015 to 2041 based on the standard pricing option provided in Schedule 37, where applicable. Rates could increase if renewable generation projects qualify for the renewable pricing option.
[2] These values represent the potential savings for an individual Basin irrigator.
[NA] No additional analysis was performed.

Chapter 8
Next Steps

While Federal legislation for the KBRA or an alternative settlement agreement is one means of advancing the CAPP, another opportunity is through the Enhancement Act. By using the Enhancement Act, Reclamation would undertake a Federal feasibility study in conjunction with a local non-Federal Project Sponsor(s) to advance and ultimately implement the CAPP preferred alternative. The next steps to advance the CAPP Feasibility Study are defined in Directive and Standard (D&S) CMP 09-02, and are presented below.

1. Identify the Project Sponsor(s). Reclamation would work with the Basin irrigation community to identify non-Federal organizations or agencies to act as the Project Sponsor(s) in the On- and Off-Project areas. The Project Sponsor(s) would help Reclamation define the CAPP's next steps, including the alternatives to be investigated in the feasibility study.

2. Prepare a Plan of Study. The Plan of Study defines the study elements of the feasibility study and clearly defines its objectives and scope. The Plan of Study also defines the role of the Project Sponsor(s) and cost sharing including any in-kind services. The alternatives defined in this IAIR would provide the foundation for the Plan of Study. There are two actions required of the Project Sponsor(s) to define the CAPP Feasibility Study scope:

- The Project Sponsor(s) would take a lead role in the development and advancement of new Federal legislation to serve the Off-Project area. Without this, Reclamation's authority is limited to the On-Project area.
- The Project Sponsor(s) would take a lead role in advancing changes to the OPUC and CPUC regulations and policies effecting opportunities to reduce irrigation power costs. These changes include the evolving time-of-use and shared renewable programs in both states, where new policies could provide cost relief as defined in several alternatives presented in this IAIR.

3. Prepare the CAPP Feasibility Study. Reclamation would conduct the CAPP Feasibility Study in coordination with the Project Sponsor(s) to define the best alternatives for achieving the CAPP objectives, including economic justification for the preferred alternative. To receive Federal funding and environmental clearance for project development, the feasibility study would be performed in conjunction with environmental compliance processes such as those falling under the National Environmental Policy Act, Endangered Species Act, and other laws and regulations. While the Enhancement Act allows for 100 percent non-reimbursable funding for the feasibility study (under the D&S, feasibility studies normally include some element of cost share), in the absence of Congressional action providing separate funding, project development would be fully reimbursable under the Reclamation Act.