Exhibit A

Exhibit A
Demand Response
Request for Proposals
PacifiCorp

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PURPOSE AND SUMMARY OF RFP

This Request for Proposals (RFP) is seeking bids for Implementation Contractors for Demand Response (DR) program resources from qualified suppliers capable of delivering seasonal and/or year-round demand reductions (kW) within PacifiCorp's service territory.

The purpose of this document is to provide interested parties with information necessary to prepare and submit a proposal to implement one or more demand response programs as specified in the *Intent of RFP* Section below. Bidders should provide separate responses, timelines and budgets for each proposed program. Multiple Bidders may be selected to meet the intent of this RFP. The Company reserves the right to make multiple awards to multiple vendors for any combination of programs proposed.

Long Term Planning Needs

PacifiCorp's 2019 IRP[1] identified the addition of 178 MW of DR system wide by 2029 along with 595 MW of energy storage co-located with 1,823 MW solar, and 1,920 MW wind by 2023 as the major resource additions of a least cost least risk long term resource plan. To acquire these resources, the company issued the All Source 2020 RFP[2] on July 7, 2020 for large scale resources and is now issuing this RFP for cost effective DR resources.

As further reasoning for issuing this DR RFP, a condition of acknowledgement of the 2019 IRP Demand Side Management (DSM) actions by the Oregon Commission directed PacifiCorp in Order No. 20-186 to do the following:

1. *Pursue demand response acquisition with a demand response RFP. To the extent practicable, the demand response bids may be considered with bids from the all-source RFP.*
2. *Work with non-bidding stakeholders from Oregon and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both.*

To address these expectations, successful initial short list bids from this DR RFP will join final bids from the AS 2020 RFP for a combined analysis in April 2021 to determine the optimal acquisition of resources to meet system needs. As discussed with non-bidding stakeholders in the fall of 2020, PacifiCorp may select some RFP responses which initially may not be cost-effective, to design one or more pilot programs in Oregon. The goal of pilots will be to test improving a key assumption in the program design to increase the long-term cost effectiveness and scalability of a future program.

Request for Proposals

PacifiCorp is seeking cost effective direct load control (DLC) DR programs to be delivered as turnkey resources. DLC DR resources are defined as fully dispatchable or scheduled firm capacity product offerings / programs employing a controllable technology capable of performing one or more grid services throughout the year including peak shaving (load shift or curtailment) and operating reserves

[1] https://www.pacificorp.com/energy/integrated-resource-plan.html
[2] https://www.pacificorp.com/suppliers/rfps/all-source-rfp.html

(contingency, regulating, frequency). Bids for behavioral demand response and energy efficiency are not considered through this process.

Programs may target any customer type (residential, commercial, industrial, irrigation) and end use application. However, of most interest to PacifiCorp are cost-effective programs which target:

1) Oregon or Washington service territories,
2) Large commercial and industrial customers for a variety of end uses,
3) Residential and small commercial smart thermostats or water heaters, and
4) Irrigation.

Programs which are most likely to be cost effective to the system are those that are capable of delivering one or more grid services as they are able to meet the following characteristics:

- Are visible to CAISO's market processes via a Settlement Quality Meter Data plan.
- Provide a response at short notice, with limited restrictions on duration and number of events.
- Are capable of scaling to 25 MW or beyond.

At a *minimum*, all eligible DR program responses are required to meet the following performance characteristics:

- Able to meet requirements for integration with PacifiCorp's Energy Management System
- Day ahead notice for events
- Able to achieve 2 MW of response within 3-5 years
- PacifiCorp is able to control initiation of events through vendor provided hardware and software for device aggregation
- Meets all program design, qualification and equity considerations as outlined in this RFP

Consideration of Pilots

Bids determined to be uneconomic to the system as proposed may be invited by PacifiCorp to consider a Pilot scope in Oregon only. As per Order No. 20-186 noted above, the Oregon Commission is interested in identifying and testing key program design assumptions which, if successfully improved, may lead to cost effective scaling of DR programs. Pilots are experiments of limited scope, scale and duration and not undertaken for the sake of piloting but are focused experiments related to a key aspect of the program, which could further enhance the program's long-term cost-effectiveness. Examples include testing marketing/outreach strategies to increase participation of a customer segment or tests to improve technology performance and better estimates of available demand.

COMPANY OVERVIEW

PacifiCorp (Company) is one of the West's leading utilities, serving approximately 1.8 million customers across six states. PacifiCorp is headquartered in Portland, Oregon. PacifiCorp is a subsidiary of Berkshire Hathaway Energy Company and consists of two business units: Pacific Power and Rocky Mountain Power.[3] Pacific Power delivers electricity to customers in Oregon, Washington and California, and is

[3] To learn more about PacifiCorp please visit our website at: https://www.pacificorp.com/

headquartered in Portland, Oregon. Rocky Mountain Power delivers electricity to customers in Utah, Wyoming and Idaho, and is headquartered in Salt Lake City, Utah.

Although the focus for this RFP is for Oregon and Washington service territories, a more complete understanding of PacifiCorp's service territory may be helpful for respondents in designing their bids.

Pacific Power Overview

Pacific Power currently offers a small Irrigation Load Control Pilot for agricultural customers in Oregon. Pacific Power also offers a significant portfolio of energy efficiency programs, which can be found at https://www.pacificpower.net/savings-energy-choices.html. In Oregon, energy efficiency programs are delivered by Energy Trust of Oregon[4]. In total, these programs are offered to approximately 800,000 customers in 243 communities.[5] **Table 1** summarizes the approximate number of existing Pacific Power customers by state.

Table 1: Approximate Number of Customers – Pacific Power

State	Residential	Commercial & Industrial	Irrigation
California	36,000	8,500	2,000
Oregon	518,000	95,000	8,000
Washington	108,000	21,000	5,000
Total	**662,000**	**124,500**	**15,000**

Rocky Mountain Power Overview

Rocky Mountain Power services 1.1 million customers in Utah, Idaho and Wyoming.[6] Rocky Mountain Power currently offers two demand response programs, an Irrigation Load Control Program[7] for agricultural customers in Utah and Idaho and an A/C Load Control (Cool Keeper) Program for its residential and small commercial customers in Utah. In addition, there are two residential customer sited battery pilots operational in Utah. Soleil Lofts is a 600-unit multifamily building with a 4.8 MW virtual power plant consisting of solar PV plus controlled battery storage where residents can benefit from backup power during grid outages and RMP dispatches the storage for grid needs when available. An additional customer sited battery program was approved in summer 2020. RMP also offers a significant portfolio of energy efficiency programs, which can be found at https://www.rockymountainpower.net/savings-energy-choices.html. **Table 2** summarizes the approximate number of existing Rocky Mountain customers by state.

[4] https://www.energytrust.org/

[5] A service territory map of Pacific Power can be found at https://www.pacificpower.net/community/service-area.html

[6] A service territory map of Rocky Mountain Power can be found at https://www.rockymountainpower.net/community/service-area.html

[7] More information on Rocky Mountain Power's Irrigation Load Control Program for the following Utah and Idaho can be found at https://www.rockymountainpower.net/savings-energy-choices/business/irrigation-load-control.html.

Table 2: Approximate Number of Customers – Rocky Mountain Power

State	Residential	Commercial & Industrial	Irrigation
Utah	776,000	101,000	3,000
Idaho	59,000	11,000	5,000
Wyoming	110,000	22,000	1,000
Total	**945,000**	**134,000**	**9,000**

Assessment of Current Programs

The Company evaluates and assesses its current program offerings for energy efficiency and demand response. Reports and program evaluations by jurisdiction can be found on the Company's website at https://www.pacificorp.com/environment/demand-side-management.html. In Oregon, efficiency program evaluations can be found on Energy Trust's website at https://www.energytrust.org/about/reports-financials/. For an evaluation of the Oregon irrigation pilot program, see Appendix A, System Information.

Customer Experience

Our customers want to engage with us in new ways via increasingly diverse technologies and platforms. The Company uses "Step Change" to describe the significant customer experience expectations it wants to instill in all its Customer Solutions interactions. The Company expects Consultant(s) to provide implementation strategies that transform the current delivery paradigm and genuinely "Step Change" the way customers and vendors engage with the Company. This means providing ways for customers and vendors to interact with the Company in more efficient ways. The Company's expectation is for professional delivery of programs with consistently high customer satisfaction scores.

THE COMPANY'S ASSESSMENT OF DEMAND RESPONSE MARKET POTENTIAL

Market Potential Assessment

In 2019, PacifiCorp commissioned Applied Energy Group (AEG) to conduct a Conservation Potential Assessment (CPA)[8] across the Company's six-state service territory to inform demand side resource selections in the 2021 IRP which is currently targeted for completion April 1, 2021.[9] The CPA developed estimates of the magnitude, timing, and cost of DSM resources, including DR, likely to be available to the Company over a 20-year planning horizon. The results can also be described as the technical achievable potential for energy efficiency and demand response.

Table 3 and **Table 4** provide the identified 20-year market potential[10] at system summer and winter peak for DR resources in PacifiCorp's service territory, not including potential customer side battery, from the

[8] PacifiCorp's Demand-side Resource Potential Assessment For 2017-2036 can be found at http://www.pacificorp.com/env/dsm.html.

[9] PacifiCorp contracted with AEG to provide the 2019 CPA which can be found here (link) to inform the 2019 IRP resource selections

[10] Market potential estimates incorporate expected participation rates, but do not screen resources for cost-effectiveness.

AEG study. Existing irrigation programs in ID, UT and OR and Cool Keeper are included in these potential summary tables. **Table 5** provides the 20 year potential for customer sited storage as per the program assumptions employed in the 2021 CPA.[11]

Table 3: 2021 CPA Summer Peak Demand Response Technical Achievable Potential

	20-Year Potential (MW) Impacts – Summer Peak, Sustained Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
CA	3	2	1	**7**	6%
ID	5	8	149	**163**	28%
OR	93	57	7	**156**	5%
UT	194	129	19	**342**	5%
WA	25	19	2	**46**	5%
WY	5	38	1	**43**	3%
System	**326**	**253**	**180**	**715**	**6%**
2019 CPA	**359**	**325**	**211**	**895**	

Table 4: 2021 CPA Winter Peak Demand Response Technical Achievable Potential

	20-Year Potential (MW) Impacts – Winter Peak, Sustained Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
CA	7	2	-	9	5%
ID	11	6	-	18	5%
OR	115	54	-	168	5%
UT	140	103	-	243	6%
WA	40	16	-	56	6%
WY	11	35	-	46	3%
System	**324**	**216**	-	**540**	**7%**
2019 CPA	**286**	**173**	-	**459**	

[11] See the October 22, 2020 IRP public meeting presentation for DR battery storage assumptions, slide 12 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp_2021_IRP_PIM_October_22_2020.pdf

Table 5: 2021 CPA Technical Achievable Potential for Customer Sited Batteries

20-Year Potential (MW) Impacts – Sustained Duration			
State	Residential	Non-Residential	Total
CA	4	15	**19**
ID	22	10	**32**
OR	62	26	**88**
UT	180	74	**254**
WA	5	5	**11**
WY	8	7	**16**
System	**281**	**138**	**419**

Key underlying assumptions used by AEG to build the technical achievable potential as well as the results of the 2021 CPA are made available to bidders in Appendix A which includes links to information already posted to the PacifiCorp IRP website as well as other information on customer segment loads, equipment saturation and end use loads in each state of our service territory with a focus on Oregon and Washington.

Existing Infrastructure and Systems to Support DR

As described above, PacifiCorp currently operates two demand response programs and two smaller scale pilots nearly entirely in Rocky Mountain Power states. Each of these efforts employs a separate Demand Response Management System (DRMS) to aggregate control of individual devices to a head end connection with PacifiCorp's system wide Energy Management System (EMS), OSI's Monarch.

Table 6: Existing DR Programs and Pilots

DR Program or Pilot	DRMS Vendor	Max Controllable Load (MW) in 2020
UT Cool Keeper	Eaton	220
ID/UT Irrigation Load Control	Enel X	232
OR Irrigation Load Control	Connected Energy	1
UT Soleil Lofts & Customer Battery Tariff	Sonnen	4.8

Cyber security concerns drive strict integration requirements between third party vendor systems and PacifiCorp's system. All of these complexities can be overcome through meeting specific requirements for programs as the above listed vendor systems have done. As more fully described in the Scope of Work section and Technical Requirements, bidding vendors have the option of providing hardware and software that meets integration requirements or bidding vendors may subcontract with an existing DRMS provider where those services already meet requirements.

Distributed energy management systems (DERMS) can become a central aggregation point for multiple DER programs and may be a future option for PacifiCorp. Although PacifiCorp does not currently have a DERMS, a central vision for control of disaggregated DER control programs may become the more efficient solution for the Company, rather than continuing separate program aggregation and dispatch with separate contractors and leased control systems. The Company is currently undertaking a review of potential DERMS solutions. If selected, earliest implementation of a system wide DERMS would be Q1 2022. Bidding vendors to this RFP will be asked to provide a response to how their proposal will be positioned to transition to a new integration requirement, if needed, within 2 years and the estimated costs to do so.

Communications and Metering

As the focus of this RFP is for DR programs in Oregon and Washington service territory, additional information specific to the existing communications strategies, metering and IT infrastructure can be found in Pacific Power's 2019 Smart Grid Report[12] for Oregon.

In 2019, PacifiCorp completed installation of Advanced Metering Infrastructure (AMI) for residential and small to medium business customers less than 1 MW in Oregon and California, enabling two-way communications to each meter and the ability to connect/disconnect remotely. To enable a DR DLC program with customer equipment, in addition to installation of a switch on that equipment, the meter would need to be configured to allow remote control via the AMI network and possibly more frequent data collection than current hourly readings which are transmitted daily. Any DR system would need to either leverage the AMI network or have a standalone communications network. Our current OR/CA AMI network is the Itron Gen5.

Large customer loads in Oregon and California are not included in AMI nor are customers in the WA service territory. Plans for integrating AMI into the WA service territory have not been determined at this time.

PacifiCorp is a regular participant in the Energy Imbalance Market (EIM) and as such has experience in ensuring that generating resources meet requirements for metering and scheduling capabilities whether the resource is participating and is bid into the market or is non participating and so not bid into the market yet recognized as a resource that can be netted against load. While to date no EIM entity has registered any DR programs with the CAISO, PacifiCorp has been actively working toward achieving this goal in 2021. Specifically, PacifiCorp is planning on using the CAISO's Proxy Demand Response (PDR)[13] product to register existing and future DR programs. As described in more detail in the following sections and the Technical Requirements in Appendix B, in order to optimize the dispatch of PacifiCorp's resource, the Company requires that resources 3MW or greater meet the CAISO technical specifications required for PDRs.

Valuation of Demand Response Resources

PacifiCorp has many years of experience in the economic dispatch of demand response programs. These programs were initially designed to curtail or shift demand during the highest system peak hours of the summer to meet system reliability requirements.

In recent years, PacifiCorp has expanded the manner in which demand response programs are dispatched *(i.e.,* use cases) beyond day ahead notice for shifting load from peak to off peak or interrupting peak load

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[12] Oregon Smart Grid Report https://edocs.puc.state.or.us/efdocs/HAQ/um1667haq135238.pdf

[13] For more information regarding PDRs, please see http://www.caiso.com/participate/Pages/Load/Default.aspx and the PDR Best Practice Manual https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Demand%20Response.

for 1-4 hours to include shorter notice events, including one-hour duration contingency reserve interruptions and fifteen-minute duration frequency response events. As PacifiCorp's generation portfolio becomes increasingly renewable with inherently greater variability, the speed, seasonality and firm characteristic of the control that some DR resources can provide are anticipated to become more valuable to the system depending on how closely those characteristics align with need.

The grid services a resource can fulfill are described below in Table 7. Each of these services is essential to balancing grid needs but due to the dynamic nature of the grid, services can be more or less valuable from day to day and hour to hour. The value of these services will also vary year to year as the mix of resources changes, impacting the amount and type of services needs to integrate those resources with load. As a result, PacifiCorp will determine which services a demand response resource will be used for in any given period, within that resource's capability.

Table 7. Balancing Area Grid Service Requirements

Grid Service		Definition	Sub-Group	Performance Specifics for Demand Response
Operating Reserves	Contingency Reserve	Used for compliance with NERC regional reliability Standard BAL-002-WECC-2a. Deployed immediately following unexpected outages of generation or transmission. Requirement is 3% of load and 3% of generation.	Non-Spinning Reserve	Deploy with less than 7.5-minute notice for 60 minutes. Not deployed in EIM.
			Spinning Reserve	Must begin responding in seconds, with full response in ten minutes, sustained for 60 minutes. Not deployed in EIM.
	Regulation Reserve	Used for compliance with NERC Control Performance Criteria in BAL-001-2. Deployed in response to variations in load and generation to manage Area Control Error.	Regulating Reserve	Deploy in no more than 30 minutes. Not deployed in EIM.
			EIM - RTPD	EIM 15-minute market. Deploy when called by EIM with 22-minute notice.
			EIM - RTD	EIM 5-minute market. Deploy when called by EIM with 5-minute notice.
	Frequency Response Reserve	Used for compliance with NERC standard BAL-003-1. Deployed during interconnection underfrequency events.		Must respond within seconds, for five minutes, with restoration within 15 minutes. Can be provided simultaneously with spinning or regulation reserve.
Capacity and Energy		Capacity and Energy Resources can help serve expected loads. Load and resources must be balanced.		Deployed on day-ahead or hour-ahead basis. Duration of one or more hours.

NERC – North American Electric Reliability Corporation
EIM – Energy Imbalance Market
RTPD – Real-Time Pre-Dispatch
RTD – Real-Time Dispatch

Demand response resources seeking to provide the grid services described in Table 7 are subject to certain key additional requirements. Demand response resources that can provide CAISO Settlement Quality Meter Data ("SQMD") result in higher value because they are visible to the CAISO's market processes and because they are able to support the required market settlement activities. SQMD is required for EIM participation but will also increase the value of a demand response program, even if it is only providing day-ahead or hour-ahead capacity and energy. Programs which aggregate large numbers of small resources may be able to utilize the Company's AMI systems to meet part of the SQMD requirements.

Resources which provide SQMD and are able to participate in the EIM Real-Time Pre-Dispatch ("RTPD") market will receive notice of interruptions 22 minutes prior to the 15-minute interval in question, i.e. prior to clock minute :00, :15, :30, or :45. Resources are required to specify a variety of operational parameters such as the minimum and maximum durations for interruptions (in 15-minute increments), the minimum time between interruptions, and whether a resource can be dispatched in increments or only as block.

Resources which provide SQMD and are able to participate in the EIM Real-Time Dispatch ("RTD") market have many of the same requirements as RTPD resources, but also must be able to respond to a new dispatch target for each five-minute interval.

Resources which do not provide SQMD can be used to provide contingency reserve or frequency response reserve if they can respond within the short notice allowed for those operating reserve services; however, the Company's volume requirements for these services are limited. Once the Company's requirements for these services are met, a lower valuation based on deployment for capacity and energy requirements would apply.

While there is added value from demand response resources that have SQMD, participate in EIM, or provide operating reserves, programs that do not meet those requirements can help the Company meet its capacity and energy requirements. The relative value of demand response programs to the system is dependent on their performance characteristics, with more value when the Company has greater flexibility. Table 8 identifies the minimum requirements for this RFP and the program performance characteristics which are likely to provide greater value. Program performance characteristics that are expected to have the greatest impact on valuation are listed first.

Table 8. DR Program Relative Value by Performance Characteristic

Program Performance Characteristic	Minimum Characteristic for RFP	Greater Value
Notice	Day Ahead	60 min, 22.5 min, 7.5 min, <2 sec
Cancellation notice	Day Ahead	Hour Ahead to no restriction
Ramp to Available Demand Reduction	1 hour	60 min, 22.5 min, 7.5 min, < 2 sec
Duration of Curtailment	1 hour / event	Shorter or longer duration as specified by PacifiCorp
Total Number of Events	10 events per season/year	More events per season/year
Event Frequency	1 per week	More events per day/week
Total Load Shed Capability	2 MW	25 MW or larger
Targeted Curtailment Capability	All participants / full load shed only (on/off)	Ability to follow changing targeted curtailment amount
Time for Program Growth to Total Load Shed Capability	3 years	Faster growth

Variations in program designs for the same customer end use demand can achieve different levels of controllability, leading to greater or lesser system value at differing costs. As a result, programs that achieve a subset of the capabilities identified above and do not require significant setup costs may be more cost effective than programs which can meet every use case. For this RFP, PacifiCorp expects that bidders will consider their cost to deliver the performance characteristics identified in Table 8 in designing their offerings. For this RFP, respondents are asked to describe how their proposed program complies with the requirements for the use cases identified in Table 7 they expect to be able to provide.

Bids will be required to include the costs and program characteristics listed in the table below in the pricing performance template, Exhibit B.

Table 9. DR Program Characteristics

Program characteristics	Description, Options
Customer Type	Residential, small commercial, large commercial, industrial, irrigation
Controlled End Use	Select from list of end uses such as water heating, space heating, cooling, lighting, or other/custom end use
kW Availability	Timing of demand availability, seasonal or year-round
Metering requirement	AMI, SQMD plan, other option, none
Notice	Day ahead, 60 min, 22.5 min, 7.5 min, <2 sec
Cancellation notice	[if applicable]
Ramp time	1 hour or less
Max Duration of Curtailment	1 hour or more
Min Duration of Curtailment	[if applicable]
Number of Events	10 or more, and any daily, weekly, or seasonal restrictions.
Event Frequency	1 or more per week of availability
Maximum kW Capability and 10 yr. forecast	2 MW in 3 years or more and sooner and 10 year forecast of annual max kW
Proposed Use Cases	☒ Capacity and Energy (applicable to all programs) ☐Non-Spinning Reserve ☐ Spinning Reserve ☐ Regulating Reserve ☐ EIM – RTPD ☐ EIM – RTD ☐ Frequency Response Reserve

Additional Value of DR

As Demand Response is a complex resource delivered with rapidly evolving technologies with the potential to greatly impact how our customers use energy services, DR programs have the potential to provide additional benefits to the utility system. Of particular value are those programs which provide benefits to highly impacted communities and vulnerable populations.[14] The secondary values may be

[14] https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=00076&year=2019&docketNumber=190837&resultSource=&page=1&query=190837&refiners=&isModal=false&omItem=false&doItem=false

difficult to quantify yet bring additional desirable qualities for our customers and will be considered to be rewarded in non-price scoring factors. These factors include;

- Diversity in staffing and supplier workforce
- Equitable customer and community benefits
  - Customer outreach and incentive design with emphasis on equitable access,
  - Community benefits in design such as critical facility focus and community resilience values,
  - Local economic development

INTENT OF RFP

The Company is requesting separate proposals by program with budgets and strategies distinguishable by state if applicable. The Company reserves the right to make multiple awards to multiple vendors for any combination of programs. Although cost effective programs will be considered, of most interest to PacifiCorp are DLC DR programs located in **Oregon and / or Washington** with the following focus.

1) **Non-Residential Curtailment**: The Company requests Bidders to submit proposals on curtailment programs for its non-residential customers in Oregon and Washington. Of most interest is an Auto-DR approach or a combination of Auto-DR with manual options for customers.
2) **Residential and/or Small Commercial Smart Thermostat or Water Heaters**: The Company requests Bidders to submit proposals on smart thermostat programs and/or DLC of water heaters for its residential and/or small non-residential customers in Oregon and / or Washington.
3) **Irrigation:** The Company requests Bidders to submit proposals to expand and enhance irrigation DR in Oregon and to begin in Washington.

Program Scope of Work

The intent of this Scope of Work is to define the expectations and objectives of the requested programs.

1) Programs must be cost-effective to the Company and its customers.
   a. The Bidder will be responsible for providing cost and performance inputs and assumptions needed to evaluate the cost effectiveness of the proposed program. (see Attachment B for response)

2) Programs must achieve 2 MW of quantifiable demand reductions within three years of operation.
   a. Bidders should discuss how savings may vary by customer type and size, and what factors may affect realized savings. Provide supporting evidence, and reference relevant history, if applicable.
   b. Bidders should be capable of providing a sufficient number of events to provide a valuable resource to the Company without disrupting customers.

3) Programs must demonstrate a strong focus on customer service, participation and satisfaction to both end use customers and internal PacifiCorp staff.
   a. Includes targeted marketing and outreach plan designed to meet customer needs and successfully recruit participants

b. Proposal demonstrates efficient implementation of customer intake, care and program delivery strategy
c. Bidders should discuss plans to respond to customers' concerns within a reasonable timeframe.
d. Programs must include a dedicated staffing plan for direct customer support and coordination with PacifiCorp staff.

4) Programs must be designed to cover all program functions as a turnkey offer
    a. Program functions can be grouped into the following four categories.
        1. Program Design/overall management
        2. Program Administration
        3. Equipment installation/O&M
        4. Connectivity, control, and bulk system integration
    b. Bidders are asked to provide a turnkey solution (covering all program functions) and itemize costs allocated to each function as well as any sub-contracting designs.
    c. In Oregon, Energy Trust delivers energy efficiency programs on behalf of all Pacific Power customers and overlaps with customer equipment and markets for demand response opportunities. Efficient coordination with Energy Trust is a requirement for any program working in Oregon.

5) PacifiCorp must be enabled to initiate events through the EMS using integrated vendor provided DRMS software and hardware which meets all cybersecurity and system integration requirements.
    a. Vendor provided DRMS must meet integration requirements
    b. PacifiCorp is only interested in programs with protected sharing of participating customer data and full visibility to demand reduction availability and achievement.

6) Bidders must meet minimum qualifications
    a. At least 5 years of experience delivering similar DR programs which met goals
    b. Demonstrated commitment to quality and customer service as evidenced by documented achievement of goals or within program evaluations.

BIDDER PROPOSAL REQUIREMENTS

Below is a summary of the key components that should be incorporated into the Bidder's proposal.

Program Design and Plan for Implementation

Bidders are expected to provide complete responses to all requests for information detailed in **Appendix B, Technical Requirements.**

Program functions can be grouped into four categories. Only bids which provide complete responses to each of these program functions as described in the technical requirements will be evaluated for cost effectiveness and potential contracting.

1. Program Design/overall management

2. Program Administration- customer participation, reporting
3. Equipment installation/O&M
4. Connectivity, control, and integration

"Start-up Plan"

Bidders should include a plan addressing any tasks needed prior to program startup. These tasks may include:

1) Development of detailed program forecast including savings targets, customer participation, and number of events.
   a. If applicable, development of any necessary measure development such as energy savings calculations, third party product testing and certification (i.e., Energy Star), installation of equipment, measure life, and cost data.
2) Development of necessary software, databases, invoicing, and reporting mechanisms.
3) Scheduled time needed to adhere to the Company's IT protocols and ensure secure data transfer of customer data.
4) Scheduled time for setup and testing of integration of resource aggregation platform with PacifiCorp's EMS.
5) Development of timeframes/schedules.
6) If needed, any coordination services needed to align and leverage Oregon program design and delivery with Energy Trust of Oregon.

Costs

Bidders must provide a budget outlining all costs and aspects associated with the proposed proposal. Costs should be identified as listed within **TAB 1 of Exhibit B, Pricing and Performance Template**. If the Bidder proposes offering financial incentives to the Company's customers these should be estimated and included in the proposed budget.

Programs should be priced to operate for five years with possible extension and modification to 10 years. Bidders should include five and ten years of pricing.

If there are any responsibilities and/or requirements the Company must undertake that are not included in the Bidder's proposal these should be clearly defined in the proposal as well as any costs the Company might incur outside of the Bidder's proposal.

BID EVALUATION

PacifiCorp's bid evaluation and selection process for this RFP will align with the process followed by the All Source 2020 RFP. The evaluation process is designed to identify the combination and amount of new resources, including both utility-scale resources and demand response, that will maximize customer benefits through the selection of bids that will satisfy projected capacity and energy needs while maintaining reliability. The models that PacifiCorp will use to evaluate and select the best combination and amount of bids are the same models that were used to evaluate proxy resources in PacifiCorp's 2019 IRP. PacifiCorp uses the IRP modeling tools to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost.

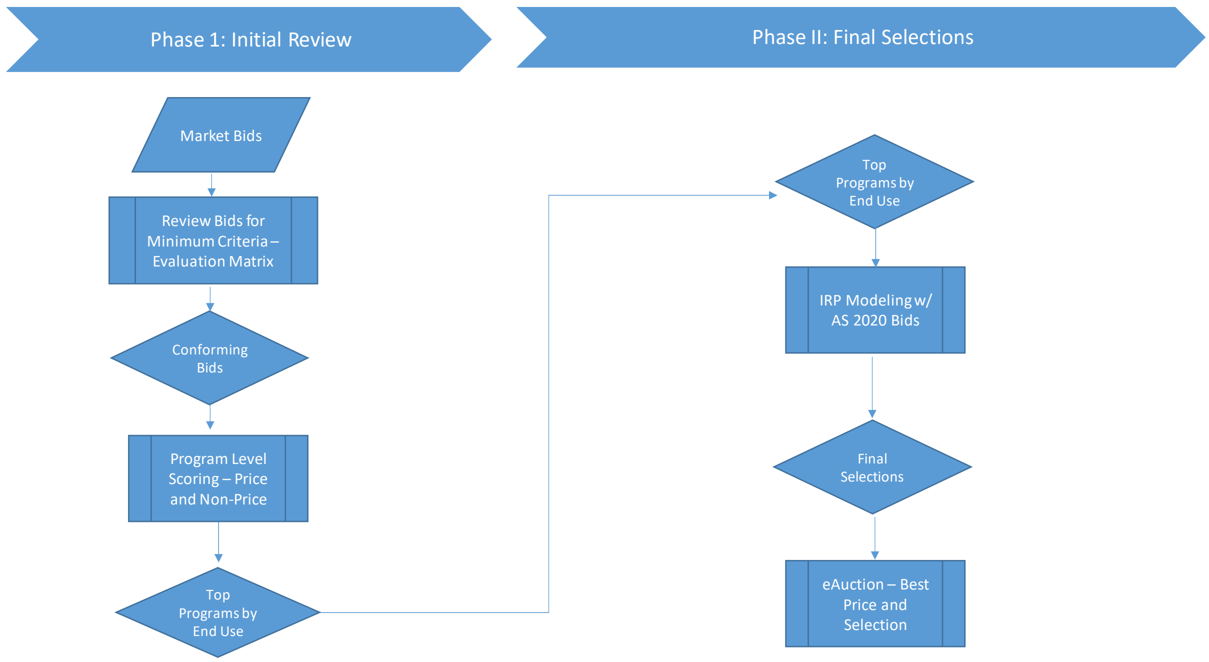

Figure 1. Bid Evaluation and Selection Process

PacifiCorp will first evaluate proposals for conformance to the RFP minimum eligibility requirements and for completeness of response to technical requirements. Remaining bids will move to the Program Level Scoring step where bids are sorted by customer end use type and then ranked to determine the Top Programs by end use to be modeled within the IRP Final Short List Model with AS2020 shortlist bids. If selected as cost effective, all those associated top ranked DR program respondents will move to the final eAuction step where the vendor with the Best Price offered to deliver the program selected by the IRP model will move forward to contracting.

1. Conformance to Minimum Requirements and Evaluated Against Technical Requirements

   Bids will initially be screened after receipt against minimum requirements for RFP conformance. Minimum screening criteria include;

   - Able to achieve 2 MW of response within 3 years
   - Day ahead notice for events
   - Able to meet requirements for integration with PacifiCorp's Energy Management System
   - PacifiCorp controls initiation of events through vendor provided hardware and software
   - Meets all program design, qualification and equity considerations as outlined in this RFP

Evaluation against technical requirements will consist of whether the bid addressed each of the components for success in responses to the **Program Design and Implementation Plan** as detailed in **Appendix B, Technical Requirements** and the proposed **Start up Plan**. Bids which fail to meet technical requirements will be eliminated from consideration.

2. Program Level Scoring (Price (80%) and Non-Price (20%))

   Bids are first grouped by state, customer type and end use type and then scored for price and non-price components. The intent of grouping bids is to identify mutually exclusive proposals for a given set of end use customers and limit IRP modeling to the top-performing proposals.

   <u>Price Scoring (80%)</u>
   Eligible bids will be evaluated using PacifiCorp's models to assess value based upon the cost (fixed and variable) and performance characteristics (kW availability and dispatchability) of the proposed program.

   Costs for bid responses will include fixed costs (upfront plus ongoing regular program expenses) and variable, based on participation or kW demand enrolled. Fixed startup costs are levelized over the life of the program and combined with annual program expenses. Variable costs are applied based on program ramp rates for participation or enrolled kW demand assumed.

   The estimated electric system benefits, or system value, of each proposal identified in the respondent's pricing template will also be quantified.

   Benefits include;

- **Energy Value** – the estimated energy savings resulting from the DR program.
  - Energy value and the frequency of deployment will vary based on proposed performance characteristics, including notice, ramp, duration, and the amount and timing (availability) of controlled load.
  - This category also captures estimated benefits resulting from the re-dispatch of generation resources that would otherwise have been providing an ancillary service in the absence of the DR program. Provision of ancillary services requires the ability to respond at short notice, but actual deployment may be infrequent, depending on the program characteristics.
  - Energy and ancillary services value will be estimated based on forecasted hourly marginal costs from the PacifiCorp's IRP production cost model.
  - This category will also capture estimated benefits from EIM participation and dispatch, where applicable. Sub-hourly benefits from EIM participation will be estimated from historical EIM price data.

- **Generation Capacity Contribution** – the degree to which a program contributes to system reliability, i.e. the ability to meet load and ancillary services requirements under strained conditions.
    - Each program's capacity contribution will be calculated based on its characteristics, including notice, duration, and the timing (availability) of controlled load.
    - Capacity contribution will be calculated consistent with PacifiCorp's 2019 IRP.[15]
    - The pricing methodology does not assign a value to generation capacity, but rather calculates the net cost of capacity for each by subtracting estimated energy, T&D, and line loss benefits from program costs.

- **Avoided Transmission and Distribution (T&D) Capacity Costs** – DR programs may reduce the need to upgrade transmission or distribution infrastructure to accommodate higher capacity.
    - Generic cost estimates from the 2019 IRP will be used unless location-specific information is available.
    - T&D capacity contribution will vary with program characteristics and may differ from generation capacity contribution.

- **Avoided Line Losses** – DR programs are expected to be reported and compensated based on the change in a customer's metered demand. However, losses are incurred in the transfer of power to end-use customers from distant generation resources, with higher losses when power is delivered at lower voltages.
    - The energy, generation capacity, and T&D capacity benefits identified above will be increased where appropriate to account for avoided line losses.

A price score will be assigned to each bid based on its costs net of its system value. This will be achieved by expressing the net cost of capacity as a "$/kW" value based on the generation capacity contribution of each bid. If a bid has a net cost of capacity that is less than zero, the $/kW value will be negative, and will be based on the maximum project output (equivalent to nameplate capacity), rather than the generation capacity contribution.

The resulting values for each bid will be force ranked, with a maximum of 80 points to the evaluated bid with the highest calculated net benefit by location, a minimum of zero (0) points to the evaluated bid with the lowest calculated net benefit; and the remaining bids scored on the 0 to 80 point scale according to the relationship of their respective calculated net benefits to those of the highest and lowest bids.

Non Price Scoring (20%)

[15] For additional details, please refer to PacifiCorp's 2019 IRP, Volume II, Appendix N: Capacity Contribution Study. Available online at: https://www.pacificorp.com/energy/integrated-resource-plan.html

20% of the bid scoring will be allocated to how well bids achieve the following qualitative characteristics within two categories.

Category 1: Diversity in staffing and supplier workforce (10 points)

- Provision of antidiscrimination policy plus provision of EEO-1, or if not a large enough business for EEO-1, actual quantities of diversity of staff by general categories, and
- >15% of total proposed contract to certified Minority and Women owned business, as subcontractor or primary

Category 2: Proposed delivery of equitable customer and community benefits with proven experience in doing so (10 points for one or more of the following)

- Customer outreach and incentive design includes emphasis on equitable access (examples include multi- lingual capability and tailored incentives) for >20% forecasted participants
- Community benefits in design such as critical facility focus and community resilience values, >20% program impacts (kW) design
- Local economic development – Program design incorporates partnering with local businesses for >50 % of delivery or equipment costs

The non-price score (either 0, 10 or 20 points) will be added to the price score (between 0-80) for each bid resulting in a final weighted score between 0 and 100 points. Bids will then be ranked from high to low total score with each state, customer type and end use type grouping.

Response templates for cost and performance information are provided to ensure consistency in bid format. (See Exhibit B)

3. Top Programs Determination and Notification

The three highest scoring bids from each group of customer type and end use will make up the Top Programs which move forward to IRP modeling with the AS 2020 bids. PacifiCorp will notify bidders that were selected to the Top Programs at the end of Phase I.

4. Final Selections and eAuction

Top program proposals will move forward for combined consideration with Short List project responses from the AS 2020 RFP where the best combination of new resources will be determined within the IRP production dispatch model as the least cost least risk portfolio. PacifiCorp will use the same proprietary models used for the Phase I initial ranking. PacifiCorp will use its System Optimizer (SO) model (the same model used by PacifiCorp to develop resource portfolios in the 2019 IRP) to develop a resource portfolio.

PacifiCorp will summarize and evaluate the results of its scenario risk analysis, considering PVRR results, to identify the specific least-cost bids.

Demand response programs which are selected within the least cost least risk portfolio of resources will move forward to eAuction where the top three bidders per group may revisit pricing to determine the Best Price to meet the selected program characteristics.

Consideration of non-price scores in valuation of final sections:

As described in step 2, bids will be eligible to receive non-price scores with up to 20% weighting used to rank the bids to select top programs. In addition, those bids that receive points for Non-Price categories, will be assigned up to 10% secondary value credit in the IRP modeling step (5% for Category 1 points and 5% for Category 2 points).

This credit of up to 10% will be applied as a reduction to program cost when modeled in the IRP tools, similar to how energy efficiency in the Northwest is assigned a conservation credit in evaluating cost effectiveness. All applicable non-price program characteristics present in the final bids will remain as required characteristics in eAuction.

SCHEDULE

Table 10. Targeted Program Project Timeline

Milestone	Date
RFP Issued	2/5/2021
Last Day for Written Questions Due	2/15/2021
Written Responses to Questions Posted	2/23/2021
Proposals Due	3/15/2021
Short List Notified	4/20/2021
Bidder's Selected	5/20/2021
Estimated Program Implementation to Begin	Q4 2021

PROPOSAL FORMAT

Bidders should organize the proposal into the following sections in either Microsoft Word files and/or Adobe Acrobat pdf files. The table of contents and organization of the proposal must be ordered as described below. Please include as many subdivisions as deemed necessary. Note: proposals should be no more than 50 pages in total, including appendices.

1) **Cover Letter** – Bidders should include an overview of its organization, rationale why the organization is a good fit, and the expected team composition, including resumes.
2) **Program Design / Plan for Implementation** – The Bidder should describe the approach and methodology for the proposed program. The Bidder should address all technical requirements listed in **Appendix B**, Technical Requirements and complete **TAB 2** of **Exhibit B,** Program Characteristics .
3) **"Start-up" Plan**
4) **Cost** – The Bidder should provide a budget for the proposed programs in a separate file. Bidders should use the **Exhibit B,** Program Characteristics, Pricing Template **(TAB 1)** with costs itemized by major program function category.

5) **References** – The Bidder should provide at least three reference and qualifications for at least two examples of similar work successfully conducted for other utilities.
6) **Timeline** – The Bidder should include a timeline demonstrating the Bidder's ability to begin offering the program to the Company's customers by the estimated program implementation deadline specified in the Schedule.