Office of the Secretary
Service Date
July 20, 2018

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND BINDING RATEMAKING TREATMENT FOR NEW WIND AND TRANSMISSION FACILITIES	)	**CASE NO. PAC-E-17-07** **ORDER NO. 34104**

On July 3, 2017, pursuant to Idaho Code § 61-526, Rocky Mountain Power, a division of PacifiCorp (the Company) applied for a Commission order granting certificates of public convenience and necessity (CPCNs) to construct or acquire four new Wyoming wind projects with a total combined capacity of 860 megawatts. Additionally, the Company requested CPCNs for associated transmission facilities, portions of which are part of the Company's Gateway West transmission project. The Company also requested binding ratemaking treatment for the investment in the combined wind and transmission projects under Idaho Code § 61-541. The Company claimed that the projects, which are subsidized by federal production tax credits (PTCs), would provide significant economic benefits for its customers.

On July 27, 2017, the Commission issued a Notice of Application and Notice of Intervention Deadline. *See* Order No. 33823. Monsanto, PacifiCorp Idaho Industrial Customers (PIIC), and the Idaho Irrigation Pumpers Association (Irrigation Pumpers) timely intervened. The Commission then set a procedural schedule, and set a date for a technical hearing. Order No. 33862, amended by Order Nos. 33940, 34001, and 34015. The Commission held a telephonic hearing for customers on May 3, 2018, and a technical hearing on May 10-11, 2018.

Prior to the start of the technical hearing, on May 9, 2018, the Company filed a settlement stipulation (Stipulation) it had entered into with Staff. The Intervenors were not parties to the Stipulation, though they fully participated in settlement discussions.

Having carefully reviewed the extensive record, including the Application, Stipulation, testimony, exhibits, and comments, the Commission now enters this Order approving the Company's request for a CPCN as more thoroughly explained below.

THE APPLICATION

In its Application, the Company proposed to invest approximately $2 billion for the construction, or acquisition, of four large-scale wind facilities, and the construction of, or modifications to, several transmission facilities. Each facility is in Wyoming. The Company claimed the wind projects would qualify for federal PTCs if they were commercially operational by December 31, 2020. Besides Idaho, the Company has asked Utah, Wyoming and Oregon to approve the projects.

The proposed wind projects would provide 860 megawatts (MW) of total generating capacity. The proposed transmission projects would require the Company to add about 180 miles of transmission line. The Company stated that the transmission lines would alleviate transmission system congestion and improve the Company's ability to manage the intermittent load produced by the new wind turbines. The Company requested approval to track the combined projects' costs and benefits and then recover the difference from customers through the Energy Cost Adjustment Mechanism (ECAM) until the costs are fully reflected in customers' base rates.

The Company stated that the estimated $2 billion cost would increase rates by about 1.9% in 2021, the expected first full year of operation of the new wind projects. However, the Company stated that because the wind projects will be fully operational by the end of 2020, it would benefit from federal PTCs. This translates to about a $137 million benefit for ratepayers over 30 years, between 2020 and 2050.

After the Company filed its Application, it updated its cost estimates, the impact of federal tax law changes, overall analysis of the projects, and risk profiles.

In the Company's Application, the wind projects originally consisted of three nominal 250 MW facilities in Wyoming (Ekola Flats, TB Flats I, and TB Flats II) and a fourth nominal 110 MW facility (McFadden Ridge II). (Tr. at 1017-19.) The proposed transmission projects included: (1) the 140-mile, Aeolus-to-Anticline 500 kV line, which includes construction of the new Aeolus and Anticline substations; (2) the five-mile Anticline to Jim Bridger 345 kV line, which includes modifications at the existing Jim Bridger substation to allow termination of the new 345 kV line; (3) installation of a voltage control device at the Latham substation; (4) a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from the Shirley Basin substation to the proposed Aeolus substation, including modifications to the existing Shirley Basin substation; (5) the reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, including modifications as required at the Freezeout substation; and (6) the reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation including modifications as required at the Freezeout and Standpipe substations. Tr. at 808-810 (In the remainder of this Order, we collectively refer to the transmission projects and the wind projects together as the "Combined Projects").

The Company's Application also asked the Commission to approve proposed ratemaking treatment for the Combined Projects. Specifically, the Company "proposes to match the costs and benefits of the Combined Projects through a new Resource Tracking Mechanism (RTM) until the costs and benefits are reflected in base rates." Tr. at 656-67.

THE SETTLEMENT STIPULATION

The Company and Commission Staff's Stipulation proposes to resolve all but one disputed issue. The Stipulation states, in sum:

- The Commission should grant a CPCN and binding ratemaking treatment for a 140-mile Aeolus-to-Bridger/Anticline 500-kV transmission line; three new Wyoming wind resources: Ekola Flats, TB Flats I and II, and Cedar Springs, totaling 1,150 MW; and related network upgrades (the Stipulated Projects);
- The Company would track new investment, energy production, and PTCs associated with the Stipulated Projects through an ECAM component called the RTM. The RTM would capture the Stipulated Projects' costs and benefits until they are recovered in base rates through a general rate case;
- The Stipulating Parties agree that any costs passed on to customers through the RTM would not exceed benefits flowing through the ECAM. The Company would defer any costs above this cap as a regulatory asset for potential recovery in the Company's next general rate case. The Company also would provide $300,000 annually in the RTM to the benefit of ratepayers;
- The Company would accept the risk that any portion of the wind projects may not qualify for PTCs, unless the failure to qualify is due to a change in the law or a force majeure event. The Company further agreed that, consistent with third-party maintenance contracts, each new wind project must always be mechanically available to delivering at least 97% of its nameplate capacity. If any wind facility cannot do this, the Company's maintenance contractor must pay liquidated damages to the Company, and the Company would pass that payment to its customers; and

- The Stipulating Parties disagreed on whether the Commission should cap the costs the Company should be allowed to recover on the overall project. Staff recommended that the Commission cap the Company's ability to recover the Stipulated Projects' costs at the Company's estimate, and the Company opposed a cap. The Stipulating Parties agreed to submit this issue to the Commission.

INTERVENORS

Intervenors Monsanto, PIIC, and the Irrigation Pumpers opposed the Company's Application and the Stipulation because they believe the project is an opportunity investment rather than a solution to an imminent resource need.

According to the Intervenors, because the Company does not need more generation resources for a long time, the projects are speculative, and their cost compared to potential ratepayer benefits is too high. Further, the variables associated with the proposal create a substantial risk that outweighs potential economic benefits. According to the Intervenors, because the Company does not immediately need the proposed generation, without a substantial guarantee of economic benefits, customers risk losing significant investment in an uncertain project. The Intervenors reason that the Company's economic analysis fails to adequately assess risks, and assigns too much risk to ratepayers. The Intervenors thus recommended the Commission deny the requested CPCN. Alternatively, if the Commission approves the proposal, the Intervenors request the approval be conditioned to moderate ratepayer risk.

FINDINGS AND CONCLUSIONS

The Company is an electric utility subject to the Commission's regulation under the Public Utilities Law. *Idaho Code* §§ 61-119 and 61-129. The Company's rates, charges, classifications and contracts for electric service in the State of Idaho, and other issues in this case, are subject to the Commission's jurisdiction. *See* Idaho Code §§ 61-526 (CPCNs), 61-528 (CPCN — Conditions), and 61-541 (Binding Ratemaking Treatment), Commission Rules of Procedure 112 (CPCN — Form and Content — Existing Utility), and 272-76 (Settlements).

The Commission reviewed the proposed settlement Stipulation under Commission Rules 271-280. Pursuant to those rules, we are not bound by any agreement of the stipulating parties. Rather, the Commission independently reviewed the proposed settlement to decide whether to approve it, reject it, or state conditions under which to accept it. The Stipulation's proponents bear the burden to prove it is just, fair, and reasonable, in the public interest, or otherwise in accordance with law or regulatory policy.

A. Need for Resources

The Company files Integrated Resource Plans (IRPs) every two years per Commission Order No. 22299, Case No. U-1500-165. The IRP is a general blueprint that describes the Company's customer base, load growth, supply-side resources, demand-side management and risk analyses. It contains information regarding available resource options, planning period forecasts, potential resource portfolios, a 20-year resource plan, and a near-term action plan. In general, the IRP addresses whether the Company needs to acquire more resources, including supply-side resources (generators and market purchases), demand-side resources (energy efficiency or demand-response programs), and transmission lines.

The Company's 2017 IRP identified the near and long-term resource needs that the Company now proposes to fill with the proposed projects. Tr. at 158, 249-50. The Company explained there is a near-term resource need of 527 MW in 2017, which will rise to 1,023 MW in 2021. Tr. at 253. The Company submitted that if the combined projects were not approved, the Company would have to fill its resource needs with uncommitted front-office transactions (FOTs), which it claimed are higher cost than a resource portfolio that includes the Combined Projects.[1] Tr. at 255. The Company acknowledged, "uncommitted FOTs are traditionally one of the lowest cost resources that can be used to meet a resource need," but argued that under the circumstances, "the availability of PTCs changes this dynamic." Tr. at 259.

The Company testified it "has an immediate resource need and that the Combined Projects would displace higher cost, higher risk [FOTs] in the near term and defer the need for other, higher-cost resources in the 2028 time frame." Tr. at 441. The Company rejected the argument that it should meet its resource needs with FOTs, and claimed it would be a "truly imprudent course of action" because the Company's undisputed modeling shows, "the Combined Projects are a superior resource choice to meet the capacity shortfall." Tr. at 442. The Company further testified that "after accounting for the updated load forecast used in [its] economic analysis of the [Combined Projects, the Company] still has an immediate capacity shortfall identified in the 2017 IRP, and moreover to meet all system requirements." *Id.*

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[1] The Company provided nine potential future price-policy scenarios, discussed *infra* at 15.

The Company acknowledged that the load forecast in its updated 2017 IRP is lower than its original estimates. Tr. at 443. However, it contended nonetheless, "[t]he capacity contribution of the Wind Projects is 207 MW, which is well below the 595 MW of capacity need in 2021 and the 3,395 MW of capacity need [estimated] in 2036 even after accounting for the updated load forecast." Tr. at 443-44. The Company summarized its claimed need stating that if it "can meet that need with resources that are lower cost and lower risk than FOTs, it is reasonable to do so." Tr. at 451.

As to the transmission projects, the Company's long-term IRP transmission planning indisputably shows the Company's long-term intention to build the Aeolus-to-Bridger/Anticline Line. *See* 2008 IRP at 281. Further, the Company clarified that the wind projects can only be accomplished with transmission projects. *See* Link Direct Tr. at 159-161. Additionally, the Company "identified and quantified three additional value streams," which include "participation in the energy imbalance market, improved transmission reliability, and reduced transmission line losses." Tr. at 163.

The Company claimed it must build the transmission line regardless of whether the wind projects come online, stating, "the issue is not if the Aeolus-to-Bridger/Anticline line will be constructed, but when." Tr. at 712. The Company clarified: "Under the proposal here, the Company can construct the line by 2020 and provide all-in net benefits to customers, rather than waiting until 2024 when PTC-eligible wind is no longer available to subsidize the line." *Id.*

Staff argued that the Company is proposing the Combined Projects "well in advance of need." Tr. at 1855. Staff nonetheless believes there is a future need that supports issuing a CPCN, but that the justification for going forward with the project now is purely economic. Staff claimed that FOTs should be considered as part of the base case, thereby making the Company's alleged need a future one. Tr. at 1883-85. Staff concluded that FOTs are viable and can be relied on, and should be pursued with the Combined Projects. *Id.*

Compared with standard CPCN requests, Staff explained it is "usually looking at projects that are based on a need for a new generating unit that would address growth or replacement of a different unit, that type of thing, so it's a reliability need, not an economic need." Tr. at 1924. Because Staff believes the Company needs the Combined Projects, with economics justifying the proposed timeline, Staff argued that the Commission should issue the CPCN on the condition that an overall project cost be capped at the Company's project estimate. Tr. at 1920-21.

Intervenors contended there is no need for the Combined Projects. They reasoned that the Company could sufficiently serve Idaho customers through at least 2026 without acquiring new generation and transmission resources. Put another way, Intervenors argued that the Company could not demonstrate a resource need justifying issuance of a CPCN. Likewise, the Intervenors claimed that uncommitted FOTs are a lower cost resource compared to the Combined Projects. *See* Phillips Supplemental Direct Tr. at 1412-13), Mullins Direct Tr. at 1511-15, Mullins Supplemental Direct Tr. at 1632-33, Yankel Cross Tr. at 1735-36. Intervenors reasoned that FOTs can be relied on, and should be pursued instead of the Combined Projects.

Additionally, the Intervenors question the integrity of the Company's 2017 IRP. *See* Tr. at 1372. Specifically, they asserted that the 2017 IRP failed to "identify any non-wind non-Wyoming opportunities as part of [the Company's] least-cost, least-risk plan." *Id.* In particular, the Intervenors argued that the Company should have explored pursuing solar power purchase agreements (PPAs). Tr. at 1372-74, 1567-68, 1593-96.

***Findings*:**

A public utility must provide "adequate, efficient, just and reasonable" service and facilities that promote the public "safety, health, comfort and convenience." Idaho Code § 61-302. However, before beginning to construct or extend "a line, plant, or system," a public utility must obtain a CPCN from the Commission, i.e. "a certificate that the present or future public convenience and necessity require or will require such construction. . . ." Idaho Code § 61-526. Notably, a CPCN is not required to extend lines, plant or system in an area already served by the utility. *Id.* Whether the "public convenience and necessity does not require or will require such construction or extension," the Commission "may, after hearing, make such order and prescribe such terms and conditions for the locating or type of the line, plant or system affected" as the Commission finds just and reasonable. *Id.*

At its core, this case presents the question of whether or not the Company has shown it requires, or will require, the proposed wind generation facilities and transmission lines to adequately, efficiently, justly and reasonably serve its customers and promote the public "health, safety and convenience." *See Id.*, § 61-302. Having reviewed the record, we find that the Company has satisfied this burden.

Prior to its 2017 IRP, the Company had not identified a resource need because it viewed FOTs as part of its available resource portfolio. *See* 2015 IRP, Case No. PAC-E-15-04. The

Company's 2017 IRP also shows available FOTs of 1,670 MW, which exceed the Company's planning reserve margin until 2026. 2017 IRP, Volume I at 91. Consequently, the Company has failed to establish that reliability requires new generation facilities. Rather, available FOTs appear sufficient to serve the Company's current load for nearly the next decade. However, we find that evidence shows that the future need for new generation facilities is most efficiently, effectively and reasonably met with the proposed projects (as modified herein) because the economic benefit captured through the PTCs is in the public interest.

The proposed transmission line has been pursued and justified by the Company's own long-term planning since 2008. Tr. at 654-55. However, absent the proposed wind facilities, record evidence is insufficient to support that the Company needs the transmission projects to stave-off near-term reliability concerns. Tr. at 1194-97. In fact, the Company has recently stated it has sufficient transmission capacity until 2028. *See* PAC-E-17-09 Application at 3, Tr. at 1884-85. Nonetheless, the Company has shown it will need the transmission projects in the future. Construction of the proposed wind projects hastens the need.

In summary, we find that the facts presented in this case—displacing FOTs with the Combined Projects—is fair, just and reasonable because the costs passed on to the utility's customers will likely be demonstrably less. Consequently, we find the Combined Projects are in the public interest.

B. The Request for Proposals (RFP) Process

The Company conducted an RFP process for the Combined Projects simultaneously with the processing of this Application. Tr. at 656. As a result, the Company provided several updates and changes to its proposals during this case.

First, in January 2018, the Company provided results of the 2017R RFP revising its request to seek approval for four new Wyoming wind projects with a total capacity of 1,170 MW (previously 860 MW). The four Wyoming projects included three of the original, benchmark facilities discussed in the Application (TB Flats I and II, now combined as a single project, and McFadden Ridge II) and two new facilities: Uinta, a 161 MW build transfer agreement (BTA), which does not depend on the new transmission projects, and Cedar Springs, a one-half BTA and one-half PPA project, totaling 400 MW. Tr. at 706. The update provided as a result of the 2017R RFP did not change the transmission portion of the Combined Project or substantially affect the overall cost projection. Tr. at 707.

Second, in February 2018, the Company identified an additional 440 MW of interconnection capacity through an update in its modeling. Tr. at 717. The Company's updated model selected TB Flats I and II, Cedar Springs, and Uinta, and replaced McFadden Ridge II with Ekola Flats. Tr. at 719-720. Likewise, the Company revised its request to seek approval for three of the original benchmark facilities, as stated in the Application (replacing McFadden Ridge II with Ekola Flats) and Uinta. The revised total MW was 1,311 MW. Tr. at 720. The Company again represented that, except for some network upgrades, the transmission project planning had not changed because of the wind project updates. Tr. at 721. The Company also reported that the revised projected capital costs for the Combined Projects had increased from approximately $2 billion to $2.245 billion. Tr. at 721.

Subsequently, on May 8, 2018, the Company and Staff agreed to remove the Company's request for approval of the Uinta project. Thus, the final Stipulation requests an order granting a CPCN for: (1) the proposed Aeolus-to-Bridger/Anticline transmission line; (2) the Ekola Flats facility; (3) the TB Flats I and II facility; and (4) the Cedar Springs project. *Id.*

As discussed above, the Intervenors objected to the fact that the majority of new capacity would be Company owned, and argued that the RFP results ignored potentially lower cost, lower risk solar PPAs. Monsanto argued, "the Company's workpapers show the Solar PPA Option provides substantially more benefits to customers on a nominal basis compared to the Combined Projects." Tr. at 1376. Monsanto submitted that the solar PPAs are also substantially less risky because "there is no transmission cost risk because the Solar PPA Option does not require the proposed Aeolus-to-Bridger/Anticline Line." Tr. at 1378. Further, the Intervenors maintain that customers would not face a risk of recovering PTC values or underperformance of facilities as it would with Company-owned wind. *Id.*

While it ultimately supported the Combined Projects through Stipulation, Staff also testified, "the solar projects are lower risk than the Combined Projects." Tr. at 1776. Staff summarized that the solar projects "have lower capital project expense than the Combined Projects; the construction of a new transmission line, which has high cost-overrun potential, is not required; and all solar bids are PPAs so the developer takes on the risk for the projects." *Id.* Staff nonetheless determined that the Combined Projects made sense from a cost-benefit standpoint so long as their higher-cost risk could be assigned to the Company through an overall project hard cap. *See* Tr. at 1923-1924.

The Company testified that it extensively tested solar options and reviewed "solar resource proposals from 31 bidders offering 109 bid alternatives for 46 solar projects. In aggregate, 6,496 MW of new solar resource capacity [was evaluated during this process]." Tr. at 245-46. According to the Company, all eligible bids "proposed PPAs with commercial operation dates ranging between November 2020 and January 2021-approximately one year before the initial ramp down in investment-tax credits." Tr. at 331. After modeling the potential solar projects, the Company analyzed the results. The Company reported that its modeling program actually guided the Company to pursue both wind and solar projects going forward. Tr. at 366-70. The Company argued that its modeling shows clearly that "the resulting solar PPAs would not displace the Combined Projects as an alternative means to deliver economic savings for customers." Tr. at 370. It concluded that its modeling "does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table." Tr. at 371.

Findings:

Throughout this case, the Company has updated its proposed wind project selection. The updates have added and subtracted different projects in different configurations with the aim of providing the most economical benefit to customers. Despite objections to the process, there is no record evidence or argument that it violated the law.

The Intervenors and Staff believe the Company's models are slanted to favor the Combined Projects. However, the record supports the Company's modeling assumptions, including projected benefits of pursuing both wind and solar at a future date. The Company's sensitivity analysis is convincing and demonstrates that solar resources cannot displace the Combined Projects. Ultimately, the economic analysis to support the Combined Projects sufficiently demonstrates that, with adequate safeguards, the Combined Projects will likely result in future cost savings for customers.

We thus find that the stipulated portfolio of wind resources is fair, just and reasonable and in the public interest, subject to conditions enumerated in the Stipulation, and an overall cost cap as discussed below.

C. Ratemaking Treatment

The Company proposed that new investment, incremental energy production, and PTCs associated with the Combined Projects pass through a RTM component of the Company's ECAM. Tr. at 19. The RTM and ECAM will capture the costs and benefits of the wind facilities until they are recovered through a general rate case. Tr. at 20. The Company proposed to record and defer, on a monthly basis, incremental capital and operating costs, net power cost savings, and PTC benefits, with each new facility beginning in the month it goes into service. Tr. at 29.

The Company would "calculate the RTM deferral as the difference between the value included in base rates for [costs and revenues] and the new value taking into account the costs and benefits of the Combined Projects as they are placed into service." Tr. at 30-31. After the Company has included the Combined Projects in base rates through a general rate case, the amount in rates would become the base plant balances. Tr. at 32-33. The base balance will be subtracted from the capital investment in subsequent annual RTM filings. *Id.* The continued use of the RTM will be re-evaluated in the next general rate case following project in-service dates.

By way of settlement, Staff supports the RTM, noting it is "the same mechanism authorized in Order No. 33954 on the Repowering Projects for existing wind sites in Case No. PAC-E-17-06." Tr. at 1918. However, Staff also notes that "the Stipulated Projects in this agreement have more limitations imposed in the RTM, [which are] important because the Stipulated Projects are based on economics rather than a need for generation and capacity." Tr. at 1918. Specifically, through Stipulation, the Company has agreed to maintain a cap in the RTM until its next general rate case where it may ask, if appropriate, to remove the cap. Staff further notes that through settlement, "in recognition of receiving timely investment recovery through the RTM and ECAM, the Company will provide $300,000 annually in a Regulatory Liability account from the first Stipulated Project in-service date until the next general rate case." Tr. at 1919.

The Company and Staff agreed that the RTM calculation will use a 9.2% pre-tax rate of return on investment, which equates to an after-tax return on investment of 6.96%. Stipulation at 4. Following the next general rate case, the return on the net plant balance will be consistent with the rate of return authorized by the Commission in that case. The Company and Staff reserved all rights to challenge the rate of return in future rate cases. *Id.* at 5. Further, actual capital costs included in the RTM, before the next general rate case, cannot exceed estimated costs for the

Stipulated Projects. *Id., see also* Tr. at 721. Parties will have the opportunity to verify these costs as part of the annual audit of the ECAM deferred balance. *Id.* at 5.

The Company and Staff agreed that the Company will maintain a cap on the annual total cost of the Stipulated Projects not to exceed the annual project benefits in the ECAM and RTM. In other words, costs that are passed on to customers through the RTM will be capped at the level of benefits flowing through the ECAM. Any costs above the cap will be deferred and the Company can request recovery in its next general rate case.

Monsanto objected to having both the wind repowering and the Combined Projects tracked together in the RTM and then lumped together in the ECAM. Tr. at 1264. Monsanto reasoned that tracking the Combined Projects with the wind repower projects will make "unbundling and monitoring the impacts of these two distinct projects difficult, if not impossible." Tr. at 1264. Alternatively, Monsanto suggests imposing an alternative RTM mechanism that includes an operational guarantee imputing PTC benefits. Tr. at 1266.

Findings:

We find it fair and reasonable to approve the stipulated ratemaking treatment, including the RTM as a component of the ECAM, to capture the costs and benefits of the combined projects until they can be incorporated into base rates. Our approval of the RTM does not constitute approval of binding ratemaking treatment for the project under Idaho Code §61-541. The RTM is an appropriate tool for cost recovery in this case, and consistent with the Commission-approved recovery for the Company's wind repower project. *See* Order No. 33954.

We further find that other Stipulation provisions adequately respond to Monsanto's concerns relating to the RTM. The Company guaranteed, through third-party maintenance contracts, a 97% rate of mechanical availability and performance of the new wind facilities. Stipulation at 7. Should the wind facilities not be available to generate, liquidated damages will be assessed and credited to customers through the ECAM. *Id.* Importantly, the Stipulation also states that the Company will bear the risks related to any portion of the wind projects that do not qualify for PTCs due to completion delays beyond the timelines associated with the 5% safe harbor. *Id.* at 6. PTCs will be imputed to each such project should the Company fail to qualify for the PTCs. Accordingly, we find the proposed ratemaking mechanism will control costs and the impact to customers and, combined with other provisions of the settlement, is fair, just and reasonable. We thus approve the Company's request to establish the stipulated RTM.

D. Settlement Stipulation & Overall Cost Cap

As discussed herein, we find the Stipulation appropriately resolves the issues relating to the Combined Projects. We further find that the Stipulation is a reasonable compromise of the complex and contested issues in this case. We recognize the Intervenors' opposition to both the proposed project and the Settlement terms. The thorough argument and analyses of the issues assisted in our ultimate decision to impose an overall cost cap set at the Company's overall project estimate. *See* Tr. at 102-103.[2]

Accordingly, we condition our acceptance of the Stipulation upon the setting of an overall capital cost cap at the project estimate. There is little dispute that the Combined Projects are being proposed based on an economic benefit that can be realized through the value of PTCs. The time within which the Company can capture this benefit is limited. The Company has presented substantial and competent evidence that seizing this opportunity will result in a better outcome for its customers. However, because the justification is economic in nature, as opposed to purely reliable and safe service, we find that the risk inherent in this business decision should not be entirely borne by the ratepayers. A cost cap reduces ratepayer risk and compels the Company to rely on its models that predict benefits. We find this fairly balances risk between the Company and its customers.

We thus find that the Stipulation is just, fair and reasonable, in the public interest, and in accordance with the law and regulatory policy of this state. We therefore approve the requested CPCN pursuant to the terms of the Stipulation, and impose a cost cap condition. IDAPA 31.01.01.275 and .276.

INTERVENOR FUNDING

Intervenor funding is available under Idaho Code § 61-617A and Commission Rules of Procedure 161 through 165. Idaho Code § 61-617A(1) states it is the "policy of [Idaho] to encourage participation at all stages of all proceedings before this Commission so that all affected customers receive full and fair representation in those proceedings." The statute authorizes the Commission to order any regulated utility with intrastate annual revenues exceeding $3.5 million to pay all or a portion of the costs of one or more parties. Idaho Code § 61-617A(2).

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[2] The Company's actual estimated capital cost, removing the Uinta project and associated interconnection upgrades, as reflected in the proposed stipulation, is a confidential figure. That amount can be found in the Company's Settlement Testimony, at page 8. (TR 102-103). In this order, we will refer to that number as the "project estimate."

Intervenor funding costs include legal fees, witness fees, and transportation and other expenses so long as the total funding for all intervening parties does not exceed $40,000 in any proceeding. *Id.* The Commission must consider the following factors when deciding whether to award intervenor funding:

(1) That the participation of the intervenor has materially contributed to the Commission's decision;

(2) That the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor;

(3) The recommendation made by the intervenor differs materially from the testimony and exhibits of the Commission Staff; and

(4) The testimony and participation of the intervenor addressed issues of concern to the general body of customers.

Id. To obtain an award of intervenor funding, an intervenor must further comply with Commission Procedural Rules 161-165. IDAPA 31.01.01.161-165. The petition must itemize expenses by category, explain why the costs constitute a significant financial hardship, and state the customer class on whose behalf the intervenor participated. Rule 162; IDAPA 31.01.01.162.

Here, the Commission received one timely intervenor funding petition, from the Irrigation Pumpers for $51,614.32. This amount consists of legal fees of $19,065.22, witness fees of $31,500.00, and expenses of $1,049.10. Application for Intervenor Funding of the Idaho Irrigation Pumpers Association, Inc. at Ex. A. Irrigation Pumpers is a non-profit corporation representing farmers' interests in electric utility matters in southern Idaho. *Id.* at 3. This amount represents 210 witness hours at $150/hour and legal expenses at $200/hour (attorney rate) and $90/hour (paralegal rate). *Id.* Irrigation Pumpers filed approximately 43 pages of direct and supplemental testimony, and participated in the technical hearing.

Irrigation Pumpers stated that it relies solely on dues and contributions voluntarily paid by its due-paying members, having only one part-time paid contractor who shares office space in Boise, and a financial hardship thus exists in relation to the expenses it accrued to participate in this matter. Application at 3.

Irrigation Pumpers further stated that its position materially differed from that of the Commission Staff because it argued that the Commission should deny the requested CPCN that Staff settled on with the Company. While it did not differentiate itself from the other Intervenors, it stated that it "showed the continued trend of decreasing natural gas prices since the time of [the Company's] initial filing and provided additional evidence that this low natural gas price environment would continue into the foreseeable future," and that "risks that the ratepayers were being asked to accept were too great and not needed." *Id.* at 4. The Irrigation Pumpers specifically represent the irrigation class of customers under Schedule 10 of the Company's system but argued positions important to the general body of ratepayers. *Id.*

Findings:

The Commission reviewed the Petition, supporting documentation, and the record of proceedings. Consistent with the policy expressed in Idaho Code § 61-617A, we encourage intervenors to participate in cases and decisions before us.

Based on their testimony and participation in this matter, we find that the Irrigation Pumpers' Petition for Intervenor Funding complies with the procedural and technical requirements set forth in Rules 161-165 of the Commission's Rules of Procedure. We thus find the Irrigation Pumpers has satisfied the criteria for an intervenor funding award under Idaho Code § 61-617A.

We find further that the Irrigation Pumpers materially contributed to our decision by addressing issues important to our consideration. This perspective was unique of the agricultural community in Eastern Idaho. The Irrigation Pumpers participated in negotiations, prepared and evaluated discovery, and testified and examined witnesses at the technical hearing. We further find that much of the Irrigation Pumpers' evidence, and its ultimate position, materially differed from that of Staff. Finally, we find that the Irrigation Pumpers addressed issues relevant to all consumers, providing us with a more complete framework in which to evaluate the case and render a decision in the public interest. We also find that the Irrigation Pumpers would suffer financial hardship without access to some intervenor funding. However, while we recognize the value of the Irrigation Pumpers' contributions, we are limited to an award of $40,000.

Having made the requisite findings under Idaho Code § 61-617A, we find it appropriate to grant the Irrigation Pumpers $40,000 in intervenor funding. This award shall be chargeable to the residential and small commercial classes. Idaho Code § 61-617A(3).

ORDER

IT IS HEREBY ORDERED that the Company and Staff's Motion to Accept the Stipulation and Settlement is approved. We grant the requested CPCN as conditioned in the Settlement.

IT IS FURTHER ORDERED that we deny binding ratemaking treatment pursuant to Idaho Code § 61-541, and approve the RTM as described in the Settlement.

IT IS FURTHER ORDERED that an overall project cost cap is set at the Company's project estimate.

IT IS FURTHER ORDERED that the Irrigation Pumpers' Petition for Intervenor Funding is granted in the amount of $40,000.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See* Idaho Code § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 20th day of July 2018.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Kristine Raper

KRISTINE RAPER, COMMISSIONER

Eric Anderson

ERIC ANDERSON, COMMISSIONER

ATTEST:

Diane M. Hanian

Diane M. Hanian
Commission Secretary

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