Final Technical Report

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Executive Summary:

The objectives of Percheron Power, LLC's (Percheron Power) Project were to design, develop, permit, and operate an innovative low-head hydro-electric generation facility on an existing engineered drop of a large irrigation canal system. The hydro-electric generation facility was designed to employ a new type of turbine and technology, called an Archimedes Hydrodynamic Screw (AHS), to harness the existing potential of the engineered drop. The goal was to demonstrate the new lower cost AHS technology system to federal agencies, irrigation districts and other system owners and to support further development of new small hydropower projects at previously marginal low-head sites in the U.S.

The Project proposal was submitted under the Advanced Hydropower Funding Opportunity Announcement (FOA) DE-FOA-0000486 of the DOE EERE WPTO which solicited applications from U.S. industry and laboratories for the development, testing, validation, modeling, and interconnection of advanced conventional hydropower systems in four topic areas[1]. Referencing the language in the FOA: A major barrier to the development of small hydro in the U.S. is the development cost. This includes licensing costs (including environmental), operation and maintenance costs, construction costs (site access and development, powerhouse, transmission interconnection), and equipment costs, thereby increasing the overall cost of electricity. The FOA solicited applications that proposed innovative hydropower technologies to lower the cost of electricity for small hydropower and improve efficiency. The goal was to reduce the Levelized Cost of Energy (LCOE) for small hydropower to less than $0.07/kWh ($70/MWh) to be competitive with existing base-load power sources such as coal-powered power plants. Topic Area 1: Sustainable Small Hydropower was focused on the need for efficient and low-cost small hydropower that can be quickly and efficiently deployed in low head/low flow existing waterways and constructed waterways. Subtopic 1.2 was further specifically focused on "component or system testing of advanced innovative technologies…. that will promote cost-effective sustainable small hydropower development thereby making previously marginal projects feasible and more sites attractive for hydropower development".

The Low-Head Technology System:
Percheron Power selected the Archimedes Hydrodynamic Screw (AHS) as the low head technology to be tested on an existing large irrigation canal. The AHS systems have been deployed quite successfully in the U.K. and Germany over the past decade, but no known installations of AHS had existed yet in the U.S.

An AHS turbine consists of three or more helix-shaped blades mounted on a central shaft. This shaft/blade assembly is installed in a trough at an angle typically between 20 and 35 degrees (relative to horizontal). Figure 1 shows a typical AHS turbine cross-section, and the powerhouse configuration is shown in Figure 2.

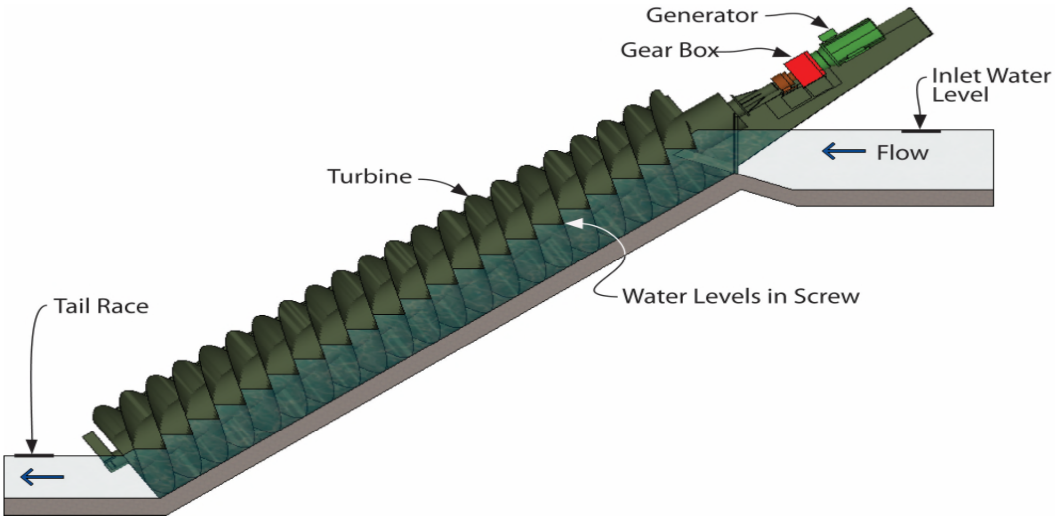

Figure 1. Cross Section of an AHS Turbine.

Water enters the top of the screw, filling it to about the midpoint of the diameter. As the water flows downhill it creates torque on the screw and causes it to turn. The screw is connected to a gearbox to step up the rotation speed and turn the generator. Systems are typically installed at a 22 to 25-degree angle (from horizontal).

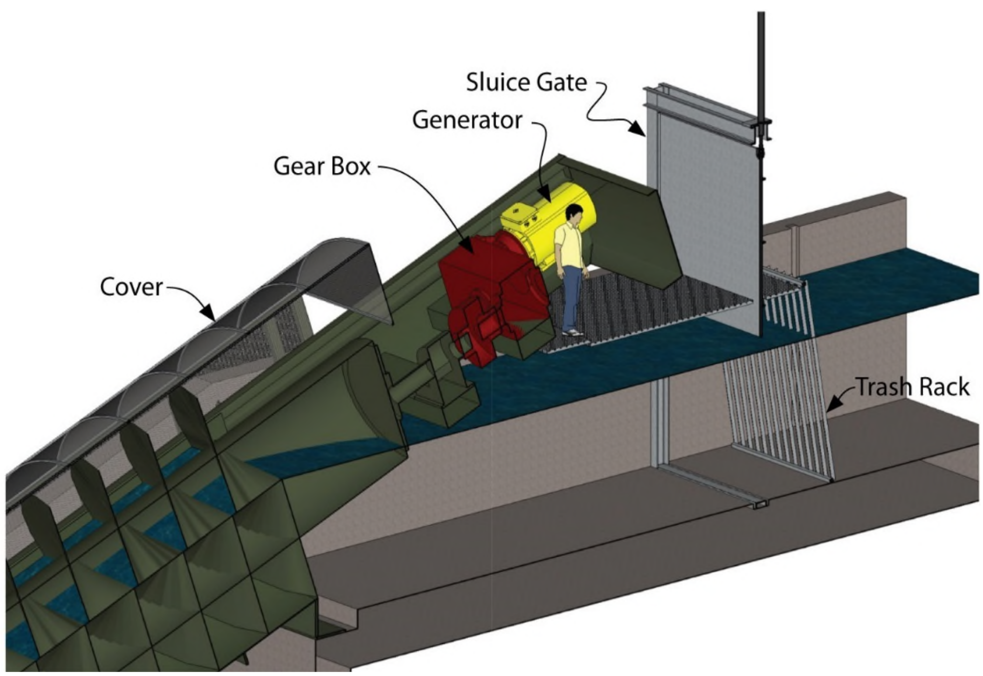

Figure 2. Depiction of an AHS turbine "installed" in a Powerhouse. Note Gearbox and Generator located above the screw at top right.

AHS turbine systems are especially suited to sites with high flows (3 to 500 cfs per AHS turbine) and work economically with head levels between 3 to 30 feet. They are technically very simple with significantly lower installed and operational costs than comparable low head Kaplan turbines. The design and construction are straight-forward and robust. Because AHS turbines rotate relatively slowly (20-50 rpm) and the inherent open design is so tolerant of debris, AHS systems are extremely reliable and can be expected to last 40 years or more with a minimum of operations and maintenance costs. The ability to continue operations during wider ranges of flow and changing tailwater elevations in the canal or waterway typically adds significantly to the overall energy per year that can be generated.

Project Tasks:
The project was divided into four key tasks: Permitting/Licensing, Design, Construction/Installation, and Commissioning; in addition to overall Project Management and Reporting. The first two tasks, Licensing/Permitting and Design, were completed in their entirety and all necessary construction documentation was submitted for Task 3, Construction/Installation. As of the date of this report, the "shovel-ready" hydro-plant has not been constructed as it could not be built within the award period due to the local utility and wholesale supplier related petitions and requests for rehearing to the Federal Energy Regulatory Commission (FERC). Further, due to significant reductions in wholesale power purchase prices over these past five years, it is expected that the project has become economically infeasible under the current award. Although there were no issues expected with the technology, or construction or operation of the plant, the project unexpectedly developed into a "bellwether" case for electric utilities that are subject to the Public Utilities Regulatory Policies Act of 1978[2] (PURPA). Although the local interconnecting utility supported buying local clean renewable energy from the new hydro plant, they were under a long-term "all requirements" contract to purchase their energy from their wholesale supplier. The local utility petitioned the FERC to determine whether they could purchase the power from this Qualifying Facility (QF) under PURPA, despite the contract with their wholesale supplier[3]. Percheron Power joined in the petition by filing an intervention in support of the local utility[4] (included as Appendix A). Although the FERC ruled in February of 2016 that the interconnecting utility was not only allowed, but obligated, to buy the power from this QF plant[5], the wholesale supplier requested rehearing[6] (which also was denied by the FERC[7]). The wholesale supplier then submitted a second petition[8] to the FERC which requested approval of a "penalty fee" to be charged to any local utility buying power from such QFs (penalty based on the lost power sales by the wholesaler for the full 20-year contract term). The FERC again denied the petition[9] and the wholesale utility again requested rehearing[10], which the FERC granted "solely for additional consideration" in August 2016[11]. There has been no action by the FERC in the past 32 months, since granting the rehearing request. In September 2018, the local utility voted to terminate its long-term supply contract with their wholesale supplier, to enable it to replace the wholesaler's base load coal plant power with less expensive and more environmentally friendly local renewable energy. However, the two parties then entered into new legal battles with the courts, the FERC and the Colorado Public Utilities Commission to define and appeal who has statutory authority in determining the "just, reasonable and non-discriminatory" termination costs of their breakup.

Under the present scenario, an acceptable 20-year Power Purchase Agreement with the interconnecting local utility is infeasible. Although various other options for delivery and purchase of the project's power output by another utility were diligently pursued, the presently mandated multiple levels of firm transmission or "wheeling" charges that would be required to move the power to another region have proven economically infeasible for this small plant, given current wholesale power rates in the West. Through evaluation of market pricing trends and the situation with the FERC and the local utility, it was determined that the project was unlikely to be completed in the near term. Percheron Power requested a further extension of the award and worked with EERE WPTO and other stakeholders to evaluate the possibility of co-locating an interested company/plant to consume the project power on-site or, alternatively, moving the project to an alternate location. It was determined that to change project locations, Percheron Power would be required to identify and select a U.S. Bureau of Reclamation (Reclamation) canal site with similar characteristics and basically start over with a new permitting/design process, then develop/construct the new project on an expedited timeline within the remaining funding. Percheron Power and EERE WPTO selected close-out of the award at this time.

Products and Outcome

Prior to selection of the Archimedes Hydrodynamic Screw (AHS) Technology System, Percheron Power investigated and evaluated both traditional and emerging turbine technologies for potential applicability to existing low-head sites in irrigation canals. The traditional technologies for this flow and head range are typically axial Kaplan and bulb-type turbines, including the associated civil works that integrate the intake/discharge structure with the powerhouse. There also were several emerging technologies, such as the French VLH turbine system and the Natel Energy, Inc. SLH system. At the time of the project initiation, the concern about deploying these innovative systems in real-time operations was operational reliability/durability. Most of the systems have multiple moving parts, require variable speed control, and did not offer a history of acceptable, long-term reliability in relatively remote or rural/unmanned field installations. Percheron Power wanted to select a technology for the project site that was robust and well proven. The goal was to successfully demonstrate and evaluate the AHS Technology System on the first canal site and then rapidly and effectively roll-out the technology to additional low-head sites.

The following advantages were identified for the AHS Technology System:

a) Simpler design with fixed blades - no wicket gates or other adjustable blades, means more reliability and longer lifetimes/less maintenance. Simple to install, operate, and maintain. This also corresponds to a simpler, and therefore more reliable, control system.
b) High efficiency turbine (85-90%) which is maintained over a very large range of flows. The efficiency remains high during rising tailwater, which is an issue with most low head sites.
c) AHS turbine system requires no cleaning and little maintenance which translates into higher operational capacity factors (typically < 2% downtime per year).

d) Robust design and ease of fabrication of components - AHS screws have been used since 300 BC to lift water; the structural design and fabrication methods are well proven.
e) More than one vendor currently available with no proprietary rights - there are at least four major suppliers in Germany and the Netherlands, in addition to others in Eastern Europe, with potential ability to develop/qualify additional suppliers in the future, particularly in the U.S., for best reliability, delivery, and pricing.
f) Rugged and wear-resistant components.
g) The AHS system can handle much larger debris than comparable Kaplan or bulb type turbines, with no deleterious effects (typically 6-inch screen clearance vs. <1-inch screen required for traditional turbines). This translates into less head loss, less blade damage/wear, and lower costs of systems and operations for debris screening and removal.
h) Applicable to a wide range of flow and head conditions (15-500 cfs per AHS turbine with a head range of 3 to 30 feet).
i) Runs at lower speeds (21 to 50 rpm for AHS, vs. >350 for Kaplan) which means longer bearing life and less wear.
j) Although not a factor in an irrigation canal, when used in rivers and other natural bodies of water, the AHS turbine also has been proven to be extremely fish-friendly, with zero mortality noted in studies in the U.K. and only minor (less than 1.4%) and recoverable scale loss for fish[12,13,14,15].
k) Lower cost per turbine than traditional conventional Kaplan or bulb-type turbines used in low head applications. In a recent engineering study in the UK., the AHS system was shown to be 22% less expensive than a traditional Kaplan Turbine system, in terms of capital cost per MWh per year[16].
l) No impact to existing canal drop structures and irrigation operations. A key requirement of Reclamation and other irrigation system operators is that power production must not interfere with the primary irrigation mission. The AHS Technology System utilizes passive control and overshot protection features and leaves the existing engineered drop structures totally intact. The AHS turbine modules are installed on a parallel waterway with passive overflow protection in the event of load rejection or other circumstance.
m) More than 50 AHS small hydro systems were currently in operation in the U.K. and Germany in 2012, with a combined operational experience of more than 100 years (over 400 are now in operation in the EU in 2019).

One of the key goals of the FOA was to demonstrate that the Levelized Cost of Energy (LCOE) for small hydropower could be reduced to less than \$0.07/kWh (\$70/MWh) to be competitive with existing base-load power sources such as coal-powered power plants. By utilizing the AHS technology for the proposed project, it was determined that the LCOE would be reduced by 40% over traditional Kaplan or bulb-type turbine systems for the proposed project. Although still "expensive", the AHS turbine system equipment was roughly half the cost of two other turbine system equipment vendor quotes for the same site (same flow/head conditions). These cost estimates and vendor quotes for the “Standard Kaplan” vs. “Innovative AHS” Cases were reviewed and certified by a licensed professional engineer.

It is anticipated that significant cost reductions could be realized for the AHS technology system for the second and further plants. The number of AHS turbines and turbine suppliers has been increasing in Europe which will provide more price competition. In the longer term, U.S. suppliers and/or manufactures could be qualified which would avoid importing/shipping costs and would also minimize price instabilities due to the value of the U.S. dollar against foreign currency. The overall permitting, design and control system costs would be expected to similarly be reduced after design and installation of the first system in the U.S. An LCOE analysis was performed for the Second Plant using the AHS turbine system and taking these experience factors into account, demonstrated an expected LCOE of $69/MWh.

Description of Key Tasks and Accomplishments:

Task 1: Licensing/Permitting

All key deliverables for this task were completed. The selected canal site was in southeastern Colorado on an existing engineered drop structure that has been in operation for over 100 years without producing any hydropower. Since the canal is part of a Reclamation Project, Percheron Power was required to develop the AHS Demonstration Project site through a Lease of Power Privilege (LOPP) with Reclamation, in conjunction with the local irrigation association system operator ("Water Association"). A Lease of Power Privilege by Reclamation is an alternative method to other licensing by the FERC for federally-owned conduits. Both Reclamation and DOE completed a National Environmental Policy Act (NEPA) review of the project and issued NEPA Categorical Exclusions for the project.

The LOPP between the Water Association, Percheron Power and Reclamation was executed in December 2014 and required construction within five years. Other agreements developed and executed for construction of the project included: Memorandum of Agreement with the Water Association, Interconnection Agreement with the local utility, Memorandum of Understanding for the Power Purchase Agreement (PPA) with the local utility, Memorandum of Agreement with the Colorado State Historic Preservation Office (SHPO), exclusive Easement Agreement with the landowner; Preliminary LOPP and Contributed Funds Agreement, Project Management Plan, Safety Plan, Emergency Action Plan and Operations Agreement required by Reclamation.

Task 2: Design

This Task was fully completed, including all civil, structural, electrical, HVAC, and building design work and the Project received final design approval for construction from Reclamation. Final design documents and formal specifications were developed and provided as a bid package for competitive solicitation. A local General Contractor was selected for the Balance of Plant and Civil Works and a formal Construction Contract was executed. A separate Request for Proposals and specifications were developed for the turbine system. The turbine system consisted of three AHS turbines in parallel (as shown below). Compact AHS assemblies, with an integral trough under the turbine, were selected for ease of installation on site. The plant had a design flow capacity of 1000 cfs combined through the three turbines and was expected to produce about one MW during the irrigation season, making it one of the largest demonstrations of the AHS technology in the world. Following an international competitive bid process, a Turbine System Supply Agreement was negotiated and executed with the selected bidder.

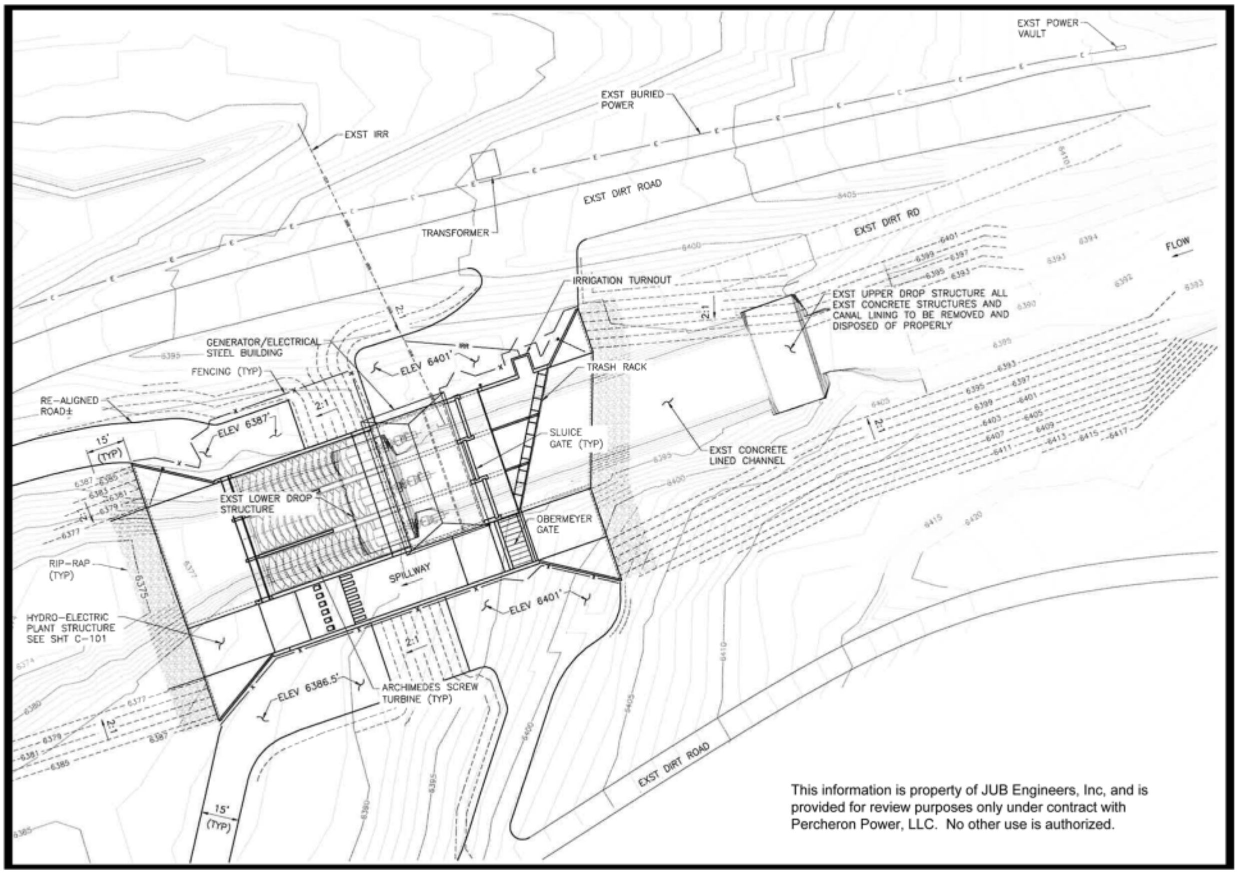

*Figure **3**. Plan View of "in canal" Project Design*

A key requirement of Percheron Power's Project was that the existing canal system must continue to be operated such that it meets all water flow, water level, and water delivery requirements**.** The best way to achieve consensus on the plant design was to involve Reclamation and other stakeholders early on. The local Water Association, utility, Reclamation, and other interested stakeholders were involved in reviewing and providing feedback and approvals on the conceptual, preliminary, and detailed designs for the project. As part of this process, three different site designs were evaluated. The option selected by the Water Association was the "in canal" design where a section of the existing canal would be replaced with the three turbines in parallel, as shown above in Figure 3. A full-flow bypass would be constructed along the side of the canal, with a passive Obermeyer® gate and spillway, to allow automatic diversion of any or all canal flows when needed.

Historic flow records were available from the Colorado Division of Water Resources for this Canal over the previous 22 years[17]. Percheron Power analyzed the data and developed flow duration curves for the site.[18] Figure 4 shows the flow duration curves that were generated for several periods. The analysis demonstrates a trend of increasing flow over the years. The duration curve representing flows during the period 2008-2012 was used for purposes of turbine sizing and project planning.

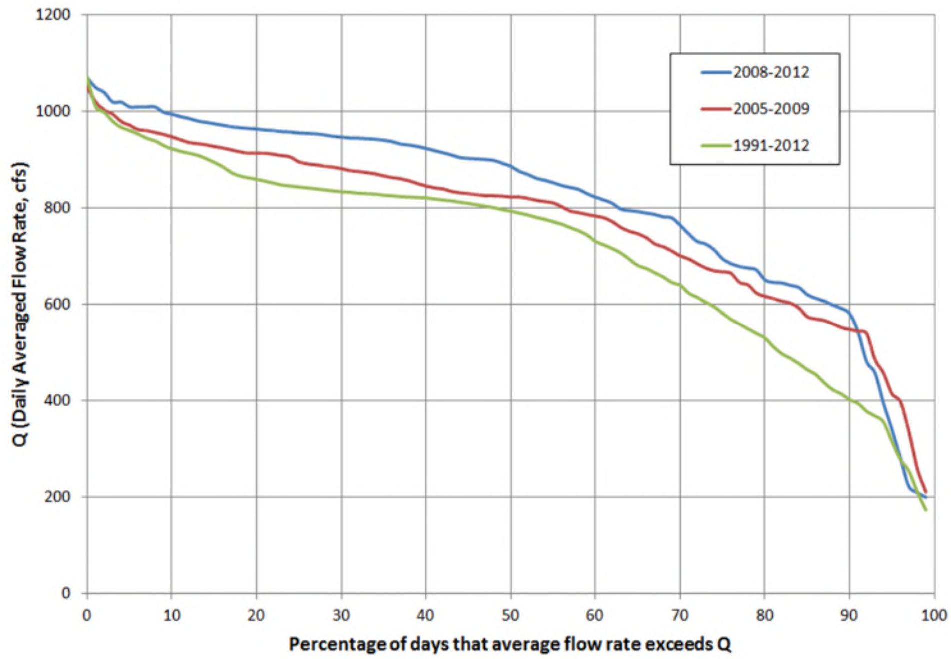

Figure 4. Flow Duration Curves for South Canal Drop 2.

The U.S. Army Corps of Engineers Hydrologic Engineering Center River Analysis Software (HEC-RAS) models were developed for modeling the water surface elevations along the canal and benchmarked against actual measurements. Reclamation Design Standards were reviewed and utilized for the design of the Plant, including: Design Standard 3: Canals and Related Structures; Engineering Monograph 25: Hydraulic Design of Stilling Basins and Energy Dissipaters; Design of Small Canal Structures; Reclamation Water Measurement Manual; and Basin Type III Spillway. The HEC-RAS model results, planned equipment and operations, site plan, structure plan and sections of the detailed design were presented and approved in design review meetings with the Water Association and Reclamation. Reclamation reviewed the final design and detailed construction specifications and planned to oversee the construction of the project to ensure there are no negative impacts to ongoing operations of the Irrigation Project. Reclamation also required the completion of a de-commissioning design and cost estimate in the event it would be desired to remove the plant at the end of the 40-year term of the LOPP.

Task 3: Construction/Installation on Site

All work in the Canal must be performed "in the dry" when the canal is empty. The Project construction plan and schedule had to ensure that the Canal would be fully operational by the start of the next irrigation season, which is typically mid to late March. On-site work needed to begin as soon as possible after canal shutdown, typically in mid-November. All required Pre-Construction documentation has been submitted to and approved by Reclamation. Construction at the Drop 2 site has been on hold pending execution of a Power Purchase

Agreement.

Planned work at the site included excavation and removal of the existing concrete drops, and earth moving and grading to set the planned powerhouse elevation. Since the new Plant would be contained essentially within the existing canal footprint (Figure 5), no significant impacts to the environment or cultural resources were expected. There are multiple areas along the existing Canal which exceed 90 feet in width. The expected maximum width of the Plant is a total of 75 feet across the turbines and bypass, with shaped inlets/outlet transition areas as wide as 110 feet. Percheron Power and its contractors would utilize the existing access roads and underground electrical distribution line adjacent to the Site.

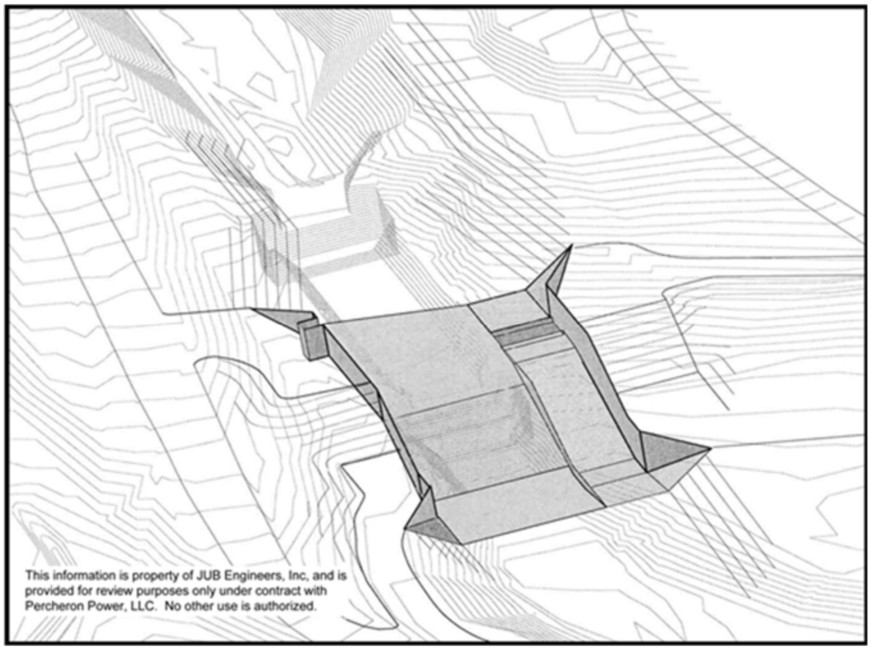

Figure 5. 3D View of Concrete Footprint for new Plant overlaid on topographic of existing Canal.

The powerhouse foundation and bypass channel would be constructed, as well as the embeds for the gates and trash rack. The turbine assemblies would be installed in the powerhouse and then the metal building enclosure would be completed. The powerhouse also incorporated a removable roof feature to allow future maintenance or removal of the turbine system.

Topographic and geotechnical surveys of the site and adjacent areas were completed by a local geotechnical firm and the results were documented in a final Geotechnical Engineering Report[19] which recommended continuous strip footing foundations embedded sufficiently into the shale to provide a more uniform moisture content condition in the shale. The resulting structural design of the foundation accommodates these soil conditions through the use of special foundation stabilization and water management techniques. The geotechnical consultants would provide further recommendations regarding soils and concrete analyses during construction.

Task 4: Testing and Commissioning

A Testing and Commissioning Plan was developed and approved by Percheron Power and the Turbine System supplier. The plan included test sequences, specific performance measurements and criteria for the different subsystems, and various contractor responsibilities and remedies. The PLC/SCADA control system would be tested to ensure appropriate system response, over all postulated normal/off normal conditions and events, particularly including loss of power. As part of the test plan, the efficiency and output of each turbine would be measured over a range of flow rates. Testing and Commissioning of the AHS system has been on hold pending execution of a Power Purchase Agreement and construction of the plant.

Plant design and operations were based on three identical AHS turbines. Two of the turbines would be connected to 460 KW induction generators that must operate at a fixed speed and are referred to as constant speed turbines. These turbines only would be operated at full capacity. The third turbine would be connected to a 445 KW induction generator that is connected to a variable speed control system. This turbine would be operated over a range of flow rates and is referred to as the variable speed turbine. All 3 turbines have a maximum capacity of 333 cfs. For flows less than 333 cfs, only the variable speed unit would run. At flows ranging from 333 cfs to 666 cfs, one of the constant speed turbines would operate at maximum capacity, and the variable speed unit would take up the difference. At flows above 666 cfs, the two constant speed turbines would both be operated at full capacity and the variable speed turbine would take up the difference. For flows above 999 cfs, all three turbines would operate at maximum capacity, and the excess flow would be routed through the bypass channel. The system would be functional and able to deliver reliable power to the grid whether 1, 2 or all 3 turbines are in operation during the irrigation season.

Percheron Power planned for the Water Association to operate and maintain the Plant. Because this AHS Plant would be the first of its kind in the U.S., training would be required and provided by the turbine manufacturer on-site. Under the terms of the Memorandum of Agreement between the Water Association and Percheron Power, Percheron Power would provide training for up to three qualified Water Association personnel. The Water Association would name a Lead Operator for the Plant and a Back-up Operator. The designated Lead Operator would have the capability to access and respond appropriately to the SCADA system, and must be able to be on-site within a reasonable time of any emergency event and for non-automatic restart of the Plant. At all times, a Lead Operator would be designated. If the Lead Operator is unavailable, the backup operator would act as the Lead Operator. Both Percheron Power and the Water Association would have physical copies of the complete operations and maintenance manuals for the Plant. Percheron Power and the Water Association would work together to determine the occurrences, notifications, and required actions for all normal and off normal events, once the control logic of the Plant was available. Percheron Power or its representative reserved the right to monitor, train and test the Lead Operator to ensure the Lead Operator is qualified to operate and maintain the Plant.

Lessons Learned:

The desired process of engaging and including stakeholders early on in the project worked very well. Percheron Power worked closely with the Water Association and Reclamation on the design and planned operation of the plant. Their input and needs also directly drove the selection of the "in canal" design option. About one year into the project, the USBR Small Conduit Hydropower and Rural Jobs Act [20] was passed which resulted in changes to Reclamation's LOPP process during the project that weren't anticipated based upon the team's experience with a successful LOPP on the same canal executed the previous year. This resulted in the team re-tracing some steps and adding other tasks and agreements to follow the new required process. There were other cost/schedule impacts to the project having to do with the geotechnical conditions of the particular site, the utility's specific interconnection requirements, as well as shipping costs/logistics due to the planned importing of the turbine system from Germany. Based on the experience with this project, it became evident that future small hydro-project plant costs and designs may continue to require site-specific adaptations even if future plants utilize a "modular" approach. For example, the surveyed soil conditions at the specific site (which included expansive clays) resulted in significant changes to the structural design, and increased both the excavation, footings and concrete costs/schedule for the plant. Additionally, the interconnection requirements and reviews/approvals are set by the interconnecting utility and the utility requires the developer to pay all costs of the interconnection. Although the expert Percheron Power utilized had performed power plant interconnection designs for many small and large operating plants around the country, he found the local utility to be very difficult to effectively work with in changing their design requirements through several rounds of reviewing/approving the interconnection design. The utility basically dictates the design and specific equipment choices based on their preferences for their own operations, so a "modular" approach to plant protection/interconnection in new future plants should not generally be expected to be applicable. Additionally, based on their experience, electrical subcontractors didn't want to perform the interconnection work as a fixed price contract when the utility was going to oversee/re-direct the work.

The project followed the new LOPP process and Reclamation's Western Colorado Office was extremely responsive and helpful, and truly wanted to make new hydropower projects work in the region. Similarly, the Water Association was an enthusiastic and helpful early partner in the project. Percheron Power also selected local contractors for the surveying and geotechnical work as well as the general contractor. In addition, Percheron Power met with the local mayor and other government and company officials about the project. This further connected the project team and the local community, both from an economic development perspective and with the expected "thrill" of working on a high-profile renewable energy project which was expected to be the first AHS plant in the nation and one of the largest in the world to date.

The local utility verbally provided their expected wholesale price for the expected PPA up front, as well as confidential copies of very recent contract/pricing agreements for other projects. The projected pricing was expected to provide a positive ROI for the project and make the plant economically feasible. However, Percheron Power was unable to secure or negotiate a binding term sheet or pricing contract since beginning negotiations and executing a non-disclosure agreement with the utility in February 2013. Percheron Power continued to press for a written agreement, and the utility wouldn't proceed without submitting a request and receiving a positive ruling from the FERC on the QF power issue prior to offering any agreement to Percheron. Percheron Power worked closely with the utility in its appeals to the FERC and expected a PPA would follow a successful ruling by the FERC. A Memorandum of Understanding (MOU) was executed between Percheron Power and the utility for the project in July 2015, following about 18 months of interactions with the FERC. Prior to the MOU, Percheron Power also had completed the interconnection design and successful negotiation and execution of the formal Interconnection Agreement with the utility. The MOU with the utility specified the power delivery/purchase from the new plant was to begin no later than July 2016, and the utility committed to continue to "negotiate in good faith on energy and capacity purchase terms" towards a PPA. Following execution of the MOU, the utility still delayed committing to any pricing for the power, apparently due to their own strategic objectives and legal/liability concerns with their wholesale supplier. Since late in 2014, the utility was able to successfully utilize the new small hydro project and Percheron Power to energize the community's support for the utility to push back (in the press and formally through the FERC) on their wholesale supplier regarding the "ceiling" on renewable energy in their full requirements contract. However, in retrospect, it was not in the utility's or their ratepayers' best interests at the time to execute a PPA at a similar price to other recent renewable energy project agreements while the utility was working to exit their entire full requirements wholesale contract. In a sense, Percheron Power and the project were the "bellwether" case for QF development under PURPA[21], but did not benefit from the case because the market for renewable energy in the West was undergoing rapid change. Under PURPA, utilities are required to buy new small power generation from QF's and *"the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery".* And, from 18CFR Part 202.302 (c)ii "*With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity."* However, once the utility achieved its key power supply objective (allowing it initially to purchase QF power and eventually freeing itself from its long-term wholesale supply contract), then the utility's self-calculated QF avoided cost rate dropped significantly. Their "avoided cost" was no longer the utility's wholesaler's cost to them (which was then well above $70/MWh), but essentially became the lowest cost available market purchase (the utility's published QF tariff is currently at $37.80/MWh[22]). PURPA, through 18 CFR Part 292.302(b), also requires utilities make available system cost data from which avoided costs may be derived. However, essentially all of the leverage and cost/pricing for new power contracts are in the utility's hands, which results in an extremely weak negotiating position for new hydropower generation projects. In addition to cutting the PPA offer price significantly for Percheron Power's new plant from the ~$70/MWh openly discussed at the beginning of the project, the draft pricing agreement eventually received from the utility included several other unfavorable clauses, giving the utility the power to: change the contract purchase price at any time, based on their estimated future avoided costs at the time; curtail the purchase at any time if the utility can generate the power for less cost; pass on any other costs/fees associated with operations or use of the power or its wholesale provider, including transmission between substations within their own service territory; and exit the entire agreement with one-year notice. Further, although the draft contract was offered following the positive FERC rulings requiring the utility to purchase the QF power, the contract also was to be contingent upon the utility's continuing determination that they were required to buy the project output under PURPA, and that such purchase/contract complied with their current contract with their full-requirements wholesale supplier.

Although Percheron Power was unable to negotiate an acceptable PPA with the utility, Percheron Power came to understand that the utility expects, as its fiduciary duty to its ratepayers, to limit its future exposure to any contract risks and to pay as little for power as possible (therefore its objective is to always procure power at the lowest available alternative market price). Basically, it became antithetical to their best interest to execute a long-term PPA in an energy market where prices were falling dramatically.

While it is true that new small power generation projects may have other "market" options if a satisfactory PPA can not be successfully negotiated with the local interconnecting utility, the realities of moving the power to another utility are quite different. The power can be "wheeled" through the existing transmission system to another off-taker with more interest and/or favorable power purchase rates in a different state. However, current interconnection and transmission rules of the FERC allow the interconnecting utilities (which includes every utility between the generation point and the eventual off-taker) to charge fees for transmission (via an Open Access Transmission Tariff, or OATT[23]). So, this ~1 MW irrigation project would be required to separately procure, contract and pay for "firm transmission" for at least 3 separate levels or "pancakes" of transmission charges with 3 separate entities to get the power out of the wholesale utility's service area. Further, even though the project could only operate for part of the year (during irrigation season), these transmission fees would be charged year-round.

In retrospect, there are several things that may have allowed the project to be finished, had they occurred at the appropriate time, including: 1) If an acceptable PPA near $70/MWh was ultimately executed, as planned at the project's outset; 2) If additional agency funding and/or very low interest rate capital (such as Clean Renewable Energy Bonds (CREBS), Reclamation Water Smart Grants, or Colorado Water Resource Board loans) was received to decrease the balance of capital costs and provide a positive investor return for the private equity portion of the project (so the project wouldn't "lose money" for the next 20 years in operation); 3) If WAPA/BPA and Reclamation agreed to a power swap for use on a Reclamation project or transmission to another utility at little or no transmission charge for the demonstration project, as part of the Colorado River Storage Project transmission allocations for WAPA preference customers or other method (done in other regions/projects); or 4) Percheron Power recognizing the inevitability of the multi-year delay upon the first filings with the FERC and working sooner with DOE-EERE WPTO to select/change sites for the project.

Conclusion:

The potential for low-head hydro in the engineered drops in both federal and private irrigation system is well known and significant[24,25]. The environmental and socio/recreational impacts of harnessing this renewable energy resource in man-made conduits are much less, and often insignificant, compared with comparable hydro-electric potential in natural water features on rivers, lakes, and streams. Yet, few new plants have been commissioned in more than two decades. Over the same time period, low head hydro installations in Germany have more than doubled[26]. The challenge is in finding economical ways to harness the hydro-electric potential in the engineered drops, and efficiently deliver the power to the grid. The system must work reliably and provide power at a competitive cost, with little or no environmental impact. Projects must also demonstrate to Reclamation, irrigation districts, and other agencies and stakeholders, that hydro-electric generation projects can be implemented in existing conduits and engineered drops with no negative impact on the structural integrity or operation of existing irrigation system infrastructure.

While the new AHS technology and proposed project met the cost targets of the FOA to be competitive with base load power prices in 2012, it was not foreseen by the DOE or Percheron Power that wholesale power purchase prices in the West would drop dramatically over the past five years (since the FOA was issued). The utility industry is undergoing a historic disruption due to the rapid wave of new large wind and subsidized solar installations. Although an LCOE of less than $70/MWh was demonstrated to be achievable, the price the "market" will now pay for new renewable energy is between $25 and $40/MWh in the West. Further, there is little interest for utilities and their rate-payers to enter into long term (20-year) PPA's when the power supply/storage/wholesale cost/transmission landscape in the U.S. is projected to continue to rapidly evolve over the next decade. Under this current scenario, even with new technology and lower LCOE, it is very difficult for new small hydro-plants to be financed and developed in irrigation canals and provide a positive ROI. It is quite possible that the capital costs of the plant could be further lowered through modularization of the design for both the turbines and civil works. Indeed, based on the knowledge gained through the design of the plant and associated equipment and construction bids, Percheron Power recently successfully completed a follow-on effort to develop a lower-cost modular Archimedes Turbine made of advanced materials[27]. While this first Composite Archimedes Hydrodynamic (CAHS) Turbine prototype was roughly half the size of the turbines planned for the Colorado site, the proven efficiency of the CAHS turbine was higher and the LCOE of production units are projected to be significantly lower than conventional AHS turbines made of steel. Additionally, if the incremental value of new hydropower can be quantified in a methodology that increases the price utilities will pay or provides other incentives for this new renewable resource, and/or very low cost capital (such as CREBS or other) can be accessed, the hundreds of existing man-made drops could be readily developed to offset existing greenhouse-gas producing energy plants. In short, the technology exists, and its reliability has been demonstrated, but the current market does not provide the necessary drivers or enablers for new plant development even at the presently reduced LCOE.

[1] U.S. Department of Energy, Energy Efficiency and Renewable Energy, Golden Field Office, Advanced Hydropower Development, Funding Opportunity Announcement Number DE-FOA-0000486, Mod. 1.**,** April 5, 2011.
[2] PURPA, Pub.L. 95–617, 92 Stat. 3117, enacted November 9, 1978.
[3] Petition for Declaratory Order and Request for Expedited Action of Delta-Montrose Electric Association under EL15-43, filed February 9, 2015.
[4] Motion to Intervene and Comments of Percheron Power, LLC, filed March 11, 2015, and referenced in 151 FERC ¶ 61,238 at 49.
[5] 151 FERC ¶ 61,238.
[6] Tri-State Generation and Transmission Request for Clarification or Rehearing under EL15-43, filed August 3, 2015.
[7] 153FERC ¶ 61,028.
[8] Petition for Declaratory Order of Tri-State Generation and Transmission under EL16-39, filed February 27, 2016.
[9] 155FERC ¶ 61,129.
[10] Tri-State Generation and Transmission Request for Rehearing under EL16-39, filed July 18, 2016.
[11] Order Granting TSGT's Request for Rehearing for Further Consideration under EL16-39, August 11, 2016.
[12] Fishery Biological Opinion on the Fish Compatibility of the Patented Hydrodynamic Screw, Dr. Harmut Spah, Nov. 2001 for Ritz-Atro.
[13] "Fish Monitoring and Live Fish Trials. Archimedes Screw Turbine, River Dart, Phase 1 Report: Live fish trials, smolts, leading edge assessment, disorientation study, outflow monitoring", Fishtek Consulting, September 2007, for Mann Power Consulting.
[14] "Archimedes Screw Turbine Fisheries Assessment. Phase II: Eels and Kelts", Fishtek Consulting, March 2008 for Mann Power Consulting.
[15] "Howsham Fish Monitoring, Assessment of fish passage through the Archimedes Turbine and associated by-wash", Fishtek Consulting, August 2009 for Mann Power Consulting.
[16] Future Energy of Yorkshire (FEY) Commissioned Study at the Sterne Mill in Copley, near Halifax, UK, www.fey.org.uk.
[17] Division of Water Resources web site at http://www.dwr.state.co.us/SurfaceWater/data/detail_graph.aspx?ID=SOUCANCO.
[18] "Flow Duration Curves for the Percheron Power Project on the ` South Canal", J.L. Straalsund, dated May 15, 2013.
[19] Letter Report, Wayne Pandorf, Buckhorn Geotech, Inc., to Jerry Straalsund, Percheron Power, LLC, "Geotechnical Engineering Report Drop # 2, South Canal Hydro, Montrose County, CO", dated September 17, 2014.
[20] Public Law 113–24, "Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act", Aug. 9, 2013.
[21] PURPA, Pub.L. 95–617, 92 Stat. 3117, enacted November 9, 1978
[22] DMEA "Qualifying Facilities. QF Tariff p. 20. "Co-Generation and Small Power Production Qualifying Facilities <100KW), https://www.dmea.com/sites/dmea/files/documents/QF%20Rate%20Tariff_2015.pdf
[23] FERC Orders 888 and 890.
[24] Hydropower Resource Assessment at Existing Reclamation Facilities, U.S. Dept of Interior, BOR, March 2011.
[25] "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants", U.S. DOE EERE Wind and Water Program, DOE-ID-11263, January 2006.
[26] Development of Market and Cost of Small Hydro Plants in Germany, Results of a report on behalf of the German Federal Ministry for Economics, J. Bard, ISET e.V. Kassel University, 2002.
[27] Utah State University College of Engineering, Video documentary of CAHS Water Testing at the Utah Water Research Laboratory, https://www.youtube.com/watch?v=Qlp1sKVZiVU, June 2018.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Delta-Montrose Electric Association	)))	**Docket No. EL15-43-000**

MOTION TO INTERVENE AND COMMENTS OF PERCHERON POWER, LLC

Pursuant to Rule 214 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure, 18 CFR § 385. 214, Percheron Power, LLC ("Percheron") hereby files this Motion to Intervene in the Petition for Declaratory Order proceeding filed by Delta-Montrose Electric Association ("DMEA") on February 9, 2015. In support thereof, Percheron states as follows:

I. Filing Party/Contacts

All correspondence and filings related to this proceeding should be addressed to the following individuals:

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[1] Designated to receive service in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, 18 CFR § 385.2010 (2014).

II. Timely Motion to Intervene

On February 9, 2015, DMEA filed a Petition for Declaratory Order and Request for Expedited Action in Docket No. EL15-43-000 ("Petition"). On February 11, 2015, the Commission noticed the Petition and set a deadline of March 11, 2015 for interventions and comments. This Motion is timely pursuant to Rule 210 of the Commission's Rules of Practice and Procedure. 18 CFR §385.210.

Pursuant to 18 CFR §385.214, Percheron hereby states its interest and grounds for intervention, as follow:

A. Statement of Interest

Percheron Power, LLC ("Percheron") is a Washington State limited liability company authorized to do business in Colorado. Certificate of Good Standing, attached as **Exhibit A**. Percheron is the owner of the qualifying facility ("QF") identified in DMEA's Petition as South Canal Drop 2 Project ("Drop 2 Project"). Percheron has requested DMEA to interconnect with its project and to purchase power therefrom under Section 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 et seq. ("PURPA"). *See* Petition, p. 5; 16 U.S.C. 824a-3. DMEA seeks a determination from the Commission whether DMEA is obligated to purchase power from Percheron under PURPA, and at what avoided cost rate. Thus, Percheron's request to interconnect and sell power to DMEA serves as a primary basis for the declaratory relief sought in DMEA's Petition.

DMEA's Petition directly affects Percheron's interests. The Commission's Order in this proceeding (a) will determine whether or not DMEA may or must purchase power from Percheron, (b) will allow DMEA to execute an interconnection agreement with Percheron, and (c) will inform the avoided cost rate at which DMEA purchases the power from the Drop 2

Project. These determinations are integral to Percheron's ownership interests in and operation of the Drop 2 Project. As such, Percheron has a right to participate as an intervenor in this docket.

Additionally, as a small power developer in the Western United States, the Commission's determinations concerning DMEA's Petition directly affect other projects which Percheron may seek to interconnect with rural electric cooperative associations ("REAs") or small utilities who are provided electric energy and capacity under long-term contracts with a wholesale supplier. A great number of REAs in the West operate under requirements contracts with a larger generation and transmission ("G&T") organization such as Tri-State Generation and Transmission Association, Inc. ("Tri-State"). Percheron's viewpoint represents that of many small power producers who rely on the continued existence of PURPA as the key underpinning of independent, distributed, and renewable power. The perspective of a QF owner is different from that of the REAs or the G&Ts and must be presented to the Commission in this proceeding. Because Percheron's participation in this docket will enable the Commission to fully consider the effect of its interpretations of PURPA and the Federal Power Act ("FPA") on the small power producers, it is also in the public interest for the Commission to grant Percheron's request to intervene.

B. Percheron's Position

Percheron supports DMEA's position in its Petition that PURPA obligates DMEA as an electric utility under that statute to purchase power from Percheron (and other QFs), regardless of the long-term requirements contract between Tri-State and DMEA ("Tri-State/DMEA Contract"). That contract may not lawfully restrict the amount of purchases that can be made from a QF. This position is consistent with PURPA and with Commission Order No. 69 promulgating the PURPA regulations, 18 C.F.R.§ 292.101 et seq. Order No. 69, 45 Fed. Reg.

12214-37, 12219 (Feb. 25, 1980). DMEA's position also comports with binding Commission precedent interpreting the obligation of REAs to purchase QF power under PURPA. *Public Service Co. of N.H. v. N.H. Electric Cooperative, Inc.*, 83 FERC P 61224, 61998-99 (1998) (a G&T cooperative and a REA "cannot lawfully bargain away any portion of the rights QFs enjoy under PURPA or [the REA's] statutory purchase obligations under PURPA").

The PURPA regulations also make clear that the purchase price of QF power must *either* be set at the utility's avoided cost rate *or* at a rate negotiated by the QF and the utility. 18 C.F.R. § 292.301(b), 303(a)(2). The limited exception that the avoided cost rate should be set at that of a full requirements supplier of a utility is inapplicable here; DMEA has only a partial requirements contract with Tri-State.

However, the rationale stated in FERC Order No. 69 for the general rule that an all requirements utility's avoided cost is the avoided cost of the supplying utility must be reassessed in light of current electric system realities. Open transmission access encouraged by Congress and FERC in the years following Order 69 has created wholesale energy markets in which supplying utilities, such as Tri-State, can sell any power otherwise displaced by a QF. Any loss in revenue anticipated in Order 69 is either easily recoverable or simply will not occur. As such, if the Commission determines that the Tri-State/DMEA Contract is in fact an all requirements, the Commission should not require that the Percheron purchase price be set at Tri-State's avoided cost rate.

At this time, Percheron takes no position concerning DMEA's argument that Tri-State should be regulated as a public utility under the FPA. Percheron's objective in this proceeding is to ensure that the Commission properly interprets PURPA, the PURPA implementing regulations, and Commission precedent to require (1) DMEA to purchase power from a QF regardless of DMEA's requirements contract with Tri-State and (2) at a purchase price set either at DMEA's avoided cost rate or a higher rate negotiated by DMEA and Percheron.

The Commission is the proper forum in which to address the PURPA issues raised in DMEA's Petition. The Commission has the authority to issue declaratory guidance on whether DMEA's requested implementation of PURPA is consistent with the Commission's policies and rules; the expertise to effectively do so; and the ability to uniformly issue a decision of great weight concerning the applicability of PURPA. In contrast, the Colorado Public Utilities is not empowered to address the Petition and a Colorado state courts lack the expertise in this specialized area of regulatory law. Further, a state-by-state approach to interpreting the interplay between PURPA and Tri-State's requirements contracts is likely to result in inconsistent outcomes across the four states in which Tri-State serves REAs. Because DMEA's Petition seeks clarification of laws and regulations subject to the Commission's jurisdiction and expertise, DMEA's request for guidance from the Commission regarding the implementation of PURPA Section 210 and the Commission's rules cannot be precluded by DMEA's decision not to first request internal dispute resolution with Tri-State. Thus, the Commission should grant DMEA's Petition and order that DMEA purchase power from Percheron at DMEA's avoided cost rate or a higher rate negotiated by DMEA and Percheron.

III. Comments In Support of DMEA's Petition for Declaratory Relief

A. FERC is the Proper Forum to Issue Declaratory Relief on the Issues Concerning PURPA.

The Commission in its discretion may issue a declaratory order to remove uncertainty. 5 U.S.C. § 554(e); *Cent. Maine Power Co.*, 34 F.P.C. 535, 535 (Aug. 19, 1965); *see also Hydrodynamics Inc.,* 146 FERC ¶ 61,193 (2014), at ¶ 29. The Commission's exercise of discretion in this instance is warranted, to address uncertainty about the implementation of

DMEA's obligations to purchase QF power under PURPA, despite the existence of a requirements contract with Tri-State. No forum other than the Commission is appropriate to issue such declaratory relief.

PURPA requires every "electric utility," including electric cooperatives, to purchase electric energy from QFs. 16 U.S.C. § 824a-3(a); 18 C.F.R. § 303(a). The Commission implements PURPA under 18 C.F.R. Part 269 ("PURPA Rules"). *See also* FERC Order. No. 69, 45 Fed. Reg. 12214, 12231 (Feb. 25, 1980). State regulatory agencies, in turn, are required to implement the Commission's PURPA rules. 16 U.S.C. § 824a-3(f)(1). The Colorado Public Utilities Commission ("CoPUC") has implemented PURPA through Rules 3900 through 3954 of the Colorado Public Utilities Code, 4 C.C.R. 723-3-3900 – 3954 ("CoPUC PURPA Rules"). However, under Colorado law, cooperative electric associations are exempt from most provisions of Colorado's Public Utilities Law by an affirmative vote of their member-consumer through their boards of directors. C.R.S. § 40-9.5-101 et seq. Exempt cooperatives are not subject to the CoPUC PURPA Rules. *See* 4 C.C.R. 723-3-3000(b). All but one of the cooperatives serving Colorado consumers, including DMEA, have exempted themselves from public utilities law in this way.[2] Accordingly, DMEA does not implement PURPA through the CoPUC and the CoPUC is not a proper forum for interpretation of DMEA's requirements under PURPA.

Rather, DMEA is a "nonregulated utility" which is responsible for implementing the Commission's PURPA regulations on its own. 16 U.S.C. § 824a-3(f)(2). DMEA's obligation to

[2] *See* Colorado Public Utilities Commission, "Deregulated Electric Cooperatives in Colorado", *available at*: http://cdn.colorado.gov/cs/Satellite?blobcol=urldata&blobheadername1=Content-Disposition&blobheadername2=Content-Type&blobheadervalue1=inline%3B+filename%3D%22Deregulated+Electric+Cooperatives+in+Colorado.pdf%22&blobheadervalue2=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1252041924902&ssbinary=true (last viewed March 4, 2015).

implement PURPA is separate from Tri-State's own obligations under PURPA or from the contractual relationship between Tri-State and DMEA. FERC Order No. 69, 45 Fed. Reg. at 12,220 ("If the qualifying facility does not consent to transmission to another utility, the first utility retains the purchase obligation. Any electric utility to which such energy and capacity is delivered must purchase this energy under the obligations set forth in these rules . . ."). To Percheron's knowledge, DMEA currently has no policies or regulations to enact PURPA. It applies the PURPA rules on a case-by-case basis. *See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC P 61304, 61644 (1983).

DMEA seeks a declaratory order from the Commission in order to remove uncertainty in its implementation of PURPA. 5 U.S.C. § 554(e); *Hydrodynamics Inc.,* 146 FERC ¶ 61,193 at ¶ 29. The Commission's exercise of jurisdiction to determine how DMEA may comply with PURPA is consistent with its exercise of jurisdiction to issue declaratory orders in other proceedings concerning the scope of utilities' obligations under PURPA. *See, e.g., Hydrodynamics Inc.,* 146 FERC ¶ 61,193; *California Public Utilities Commission*, 132 FERC P 61047, 61326 (2010). Additionally, issuance of a declaratory order in this proceeding is consistent with the Commission's policy concerning its enforcement role. *See Policy Statement*, 23 FERC at P 61,645 (the Commission's "primary role in the statutory scheme of review and enforcement is to ensure that the State regulatory authorities and nonregulated electric utilities implement regulations under section 210(f) *which are consistent with the regulations established by the Commission under section 210(a) of PURPA*") (emphasis added).

Issuance of a declaratory order would be most efficient under the circumstances. Percheron commends DMEA for requesting the Commission's guidance now, rather than merely refusing to purchase power from Percheron and forcing Percheron to petition the Commission to use its enforcement power to require the very relief on which DMEA now seeks guidance. 16 U.S.C. 824a-3(h)(2)(B). In requesting the Commission to order interconnection with Percheron's QF, DMEA is acting in the best interests of its ratepayers by minimizing litigation costs and attempting to reduce rates at which it purchases power.

Although Tri-State may argue that the Petition should be addressed in state court under the concurrent jurisdiction provision of PURPA, 16 U.S.C. 824a-g, this case is best addressed by the Commission in its expertise and due to the import of the issues raised herein. The Commission has established factors which it considers when exercising jurisdiction over matters which might be otherwise reviewable in state court: "(1) whether the Commission possesses some special expertise which makes the case peculiarly appropriate for Commission decision; (2) whether there is a need for uniformity of interpretation of the type of question raised by the dispute; and, (3) whether the case is important in relation to the regulatory responsibilities of the Commission." *Arkansas Louisiana Gas Co. v. Hall*, 7 FERC P 61175, 61322 (1979).

DMEA's analysis of these factors is accurate; each heavily weighs in favor of the Commission exercising its own jurisdiction to interpret DMEA's obligation to purchase QF power under PURPA. First, the Commission is the best equipped to issue a decision on the interpretation of PURPA and its implementing rules. Second, the need for uniformity of interpretation is critical in this case. Tri-State operates across five states and its 44 member cooperatives are bound to essentially the same requirements contract as the Tri-State/DMEA Contract. *See, e.g., Tri-State/Kit Carson Electric Cooperative, Inc. Contract*, Exhibit A to Kit Carson's Motion to Intervene (March 10, 2015). Requiring each state to address the same questions concerning the interplay between PURPA and Tri-State's requirements contracts, rather than addressing them in the Commission in the first instance, will result in inefficiencies and inconsistencies. Particularly where there is no state agency available to assist DMEA in determining whether its PURPA's requirements have been properly implemented, the Commission must assure that nonregulated utilities comply with the Congressional directive of encouraging renewable and independent power.

Finally, the Commission should issue a declaratory order in this proceeding, despite any claims by commenters or Tri-State that DMEA has failed to exhaust its administrative remedies under Tri-State Board Policy 316. Here, DMEA seeks declaratory judgment from the Commission interpreting the PURPA Rules. Nothing in Tri-State's policies can preclude DMEA's ability to seek, or the Commission's authority to issue, such guidance. Issues concerning *Percheron's* request to interconnect to DMEA does not involve a dispute between DMEA and Tri-State which Tri-State's internal dispute resolution is aimed to resolve. DMEA's PURPA obligations are its own. Percheron is not a party to the Tri-State/DMEA Contract. Percheron believes that the Tri-State/DMEA Contract cannot affect DMEA's duty to implement PURPA in any case.

Further, Percheron observes that, as properly pointed out by DMEA in their Petition at p. 27, "Section 11(a) of the Tri-State/DMEA Contract states that the contract represents the entirety of the agreement between the parties." Because the Tri-State/DMEA contract is silent regarding QF power purchases, Tri-State has no authority or jurisdiction to determine or require approval of DMEA's implementation obligations under PURPA. Further, according to DMEA, "policies adopted unilaterally by Tri-State or its Board that are not incorporated into the contract by agreement of the parties are not part of the contract and cannot be enforced." Petition, p. 27.

The Commission should disregard any suggestion that the Commission is foreclosed from issuing an order on DMEA's Petition.

B. Whether Tri-State Should Be Regulated Under the FPA is a Separate and Distinct Issue from DMEA's Obligations Under PURPA.

At this time, Percheron takes no position with respect to whether Tri-State is a jurisdictional utility under Section 201 of the FPA. This issue is distinct from whether DMEA must purchase power from Percheron and at what avoided cost. *See, e.g., Midland Power Co-op. v. Fed. Energy Regulatory Comm'n*, 774 F.3d 1, 3 (D.C. Cir. 2014) ("Section 210 of PURPA, unlike many other sections of PURPA, is neither a new section of the FPA nor an amendment of a pre-existing section."). Percheron believes that the Commission need not address the jurisdictional status of Tri-State at this time in order to issue a declaratory judgment interpreting DMEA's obligations under PURPA. *See* 5 U.S.C. § 554(e). In the interest of an expedited decision regarding DMEA's PURPA obligations and Percheron's request to interconnect to DMEA, Percheron respectfully requests that the two issues be separately addressed by the Commission, to the extent practicable.

C. PURPA Requires DMEA to Purchase Power from Percheron, Regardless of Any Purchase Limitations in the Tri-State/DMEA's Contract.

There is ambiguity in the Tri-State/DMEA concerning DMEA's ability to purchase power from QF that it does not own or control. *See* DMEA Petition, p. 24. However, even if the Tri-State/DMEA were interpreted to expressly restrict DMEA's purchases of QF power, the Commission must determine that such a provision is void to the extent it conflicts with PURPA. PURPA was enacted by Congress in 1978. The Tri-State/DMEA Contract was entered into in 2001. PURPAis part of the organic law governing utilities at the time the contract was executed, and the contractual terms must be interpreted in light of PURPA.

PURPA is clear: "[E]ach electric utility shall purchase . . . any energy and capacity which is made available from a [QF]." 18 C.F.R. § 303(a); *see also* 16 U.S.C. § 824a-3(a). An "electric utility" broadly includes REAs such as DMEA, as "any person, State agency, or Federal agency, which sells electric energy." 16 U.S.C. § 2602(4).

DMEA is correct that the Commission has expressly rejected the notion that the existence of a requirements contract between a REA and a G&T cooperative may somehow excuse the REA's statutory obligation to purchase QF power under PURPA. The Commission set forth clear guidance in FERC Order No. 69, its order adopting PURPA's implementing regulations, that "the mandate of PURPA to encourage cogeneration and small power production requires that the obligations to purchase under [18 C.F.R. 303(a)] supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility" found in the requirements contract between a REA and a wholesale supplier. FERC Order No. 69, 45 Fed. Reg. at 12,219.

The Commission affirmed its interpretation obligating an electric cooperative that is a party to a requirements contract which may otherwise limit the ability of the cooperative to purchase QF power to nonetheless comply with Section 210(a) of PURPA in *Public Service Co. of N.H. v. N.H. Electric Cooperative, Inc.*, 83 FERC ¶ 61,224 (1998) ("*Public Service Co. of N.H. I*"). A supplier in a requirements contract with an electric cooperative sought a determination from the Commission that the cooperative was not required to purchase power from QFs under Section 210 of PURPA unless the supplier consented to the transaction. Although this case involves interpretation of 18 C.F.R. § 303(d) rather than subsection 303(a), this case is squarely on point. The supplier argued that the electric cooperative had "bargained away in the [requirements contract] whatever opportunity it might have had for voluntary purchases from QFs." 83 FERC ¶ at 61,998. The Commission disagreed, holding that the supplier and the cooperative "cannot lawfully bargain away any portion of the rights QFs enjoy under PURPA or [the cooperative's] statutory purchase obligations under PURPA." *Id.* The Commission held that the cooperative was required to purchase power from any QF that could deliver its power to the cooperative, whether the QF was directly or indirectly interconnected therewith. *Public Service Co. of N.H. I* remains good law; it has not been overturned by the Commission or the courts.[3] Good law and good policy suggest that the Commission should follow its decision in *Public Service Co. of N.H. I* in this case.

D. Because the Tri-State/DMEA Contract is a Partial Requirements Contract, DMEA's Purchase Price for Percheron Power Must Be at DMEA's Avoided Cost Rate or a Higher Rate Negotiated Between DMEA and Percheron.

Percheron supports DMEA's request for an order declaring as a matter of law that the purchase price for QF power must be set either at DMEA's avoided cost rate or a higher rate negotiated with the QF. Neither Percheron nor DMEA request the Commission to determine the exact avoided cost rate in this proceeding, as such a determination is first left to DMEA as the nonregulated utility implementing the PURPA rules. However, to clarify DMEA's implementation obligations under PURPA and to avoid any subsequent complaint or other legal action by Tri-State as a result of any transaction between DMEA and Percheron, the Commission should order that Tri-State's own avoided cost rate is irrelevant to DMEA's purchase of QF power from Percheron. *See* 18 C.F.R. § 292.301(b), 303(a)(2).

The general rule established by the Commission is that the avoided cost to be paid to a QF selling power to a full requirements customer is the avoided cost of the full requirements supplier. FERC Order No. 69, 45 Fed. Reg. at 12219; *Carolina Power & Light Co.*, 48 FERC ¶

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[3] Percheron further agrees with DMEA that DMEA need not obtain a waiver of its QF purchase obligation in order to comply with its requirements contract. *Public Service Co. of N.H.* remains good law on this point, as well. 83 FERC P at 62,000-01 ("NHEC has no obligation to seek a waiver and we would not impose one upon it at another party's request").

61,101, 61,389-90 (1989). The Commission defines an "all requirements" utility as an electric utility which is legally obligated to obtain *all* of its requirements for electric energy and capacity from another utility. *See* FERC Order No. 69, 45 Fed. Reg. at 12219 ("contractual commitments into which they had entered requiring them to purchase *all of their requirements* from a wholesale supplier") (emphasis added). Because the Tri-State/DMEA Contract is a *partial* requirements contract, this rule is inapplicable here

In *Public Service Co. of N.H. v. N.H. Electric Cooperative, Inc.*, 85 FERC ¶ 61,044, 61136 (1998) ("*Public Service Co. of N.H. II*"), cited by DMEA in its Petition, the Commission interpreted the contract between the supplier utility and the requirements customer cooperative as a partial contract based on the fact that the contract permitted the cooperative to generate or purchase a portion of the cooperative's power from two other sources: grandfathered-in existing generation and QFs. Like that of the New Hampshire electric cooperative, DMEA's contract with Tri-State expressly permits DMEA to obtain a portion of its power from sources other than Tri-State: "5% of its requirements may be obtained from generation owned or controlled by" DMEA. *Tri-State/DMEA Contract*, Attachment B to DMEA's Petition, p. 2. As argued by DMEA, the Tri-State/DMEA Contract may reasonably viewed as *less* restrictive on DMEA than the contract at issue in *Public Service Co. of N.H. II* because DMEA has the opportunity to obtain non-Tri-State power on *going forward* basis, rather than merely being allowed to grandfather in its existing generation. DMEA Petition, p. 20.

Other cases cited for the general rule concerning the avoided costs of an all requirements customer are distinguishable from the case at issue. In *Roger & Emma Wahl v. Allamakee-Clayton Electric Cooperative*, 115 FERC ¶ 61,318 (2006), the parties did not dispute that the subject electric cooperative had an all requirements contract with its G&T cooperative, Dairyland Power Cooperative, under which it obtained *all* of its power needs. *See Complainants' Response to Allamakee-Clayton Electric Cooperative*, FERC Docket No. EL06-65, p. 7.[4] Nor does the existence of an all requirements appear to have been at issue in *Carolina Power & Light Co.*, 48 FERC ¶ 61,101, 61, 386 (1989) (*Carolina*). Additionally, *Carolina* involved a filing under Section 205 of the FPA to implement FERC Order No. 69's billing procedures, not a declaratory action seeking interpretation of PURPA. *See Public Service Co. of N.H. II*, 85 FERC at ¶ 61,135.

City of Longmont, 39 FERC ¶ 61,301 is inapposite to the Commission's analysis of the Tri-State/DMEA Contract because the requirements contract in *Longmont* permitted the requirements utilities only to generate approximately 1.5% of their own power through *existing* projects that were grandfathered in under the contract. The contract did not allow for any new sources of generation and was found to constitute an all requirements contract. In clear contrast, the 5% of power that DMEA currently self-generates did not come online until after DMEA and Tri-State executed their contract. Thus, the requirements contract expressly envisioned that Tri-State would not provide a portion of DMEA's *future* power needs. Further, both *City of Longmont* and *Re Oglethorpe Power Corp.*, 32 FERC ¶ 61,103 (1985), upon which *Longmont* was largely based, are also distinguishable from this case in that they were decided upon the requirements customer's request for a waiver from their 292.303(a) obligation to purchase power from QFs. The applicable standard in these cases was whether the requesting utility's strict compliance was unnecessary to encourage cogeneration and small power production. In contrast, an electric utility complying with PURPA must itself encourage cogeneration and small power production. Here, DMEA is not seeking a waiver of its purchase obligations under

[4] The all requirements contract does not appear in the record before the Commission in that case.

PURPA. The Commission relied on this distinguishing fact in *Public Service Co. of N.H.*, 85 FERC at ¶ 61,135.

Here, the Tri-State/DMEA Contract is properly characterized as a partial requirements contract. Thus, the PURPA rules dictate that DMEA must purchase Percheron power at least at its own avoided cost rate, or otherwise at a rate negotiated with the QF. 18 C.F.R. 292.304(a)(2); 18 C.F.R. § 292.301(b); *see also Public Service Co. of N.H.*, 83 FERC P at 62,001 n. 19 (an electric utility and a QF may always negotiate a purchase price other than avoided cost).

E. The Rationale in FERC Order No. 69 for Setting Purchase Price at Tri-State's Avoided Cost in Inapplicable.

Even if the Commission were to find that the DMEA/Tri-State Contract constitutes an all requirements contract, such a finding should not lead the Commission to conclude that Tri-State's avoided costs, rather than DMEA's avoided costs, constitute the proper QF purchase rate for Percheron under the circumstances. The Commission should not apply previous interpretations of Order 69 so as to limit the QF avoided cost rate to that of the supplying utility in the case of DMEA for the reasons discussed herein.

FERC Order No. 69 contemplated three separate scenarios regarding the estimated avoided cost of a non-generating utility. FERC Order No. 69, 45 Fed. Reg. at 12,219. First, the avoided cost rate might be the price of bulk purchased power ordinarily based on the average embedded cost of capacity and average energy cost on its supplying utility's system (*i.e.,* what Tri-State charges DMEA). Alternatively, the avoided cost paid to the QF may be *higher* than this avoided cost of the non-generating utility if the supplying utility can avoid the addition of new capacity. In such instances, the avoided cost would include the highest cost of the new capacity avoided by the supplying utility. Third, if the supplying utility is in an "excess capacity" situation, the loss in revenue to the supplying utility due to the QF should be assigned to the all requirements customer who, in turn, should deduct these losses from the QF. Under this third alternative, Tri-State's avoided energy cost, which may be substantially lower than the rate charged by Tri-State to DMEA, would become the relevant avoided cost measure.[5]

However, this third alternative is based on outdated assumptions in the case of Tri-State. It assumes that any lost revenue to the supplying utility due to QF power replacing the supplying utility's power will automatically result in the same fixed costs of the supplying utility being spread across fewer output units. An assumption that a large supplying utility such as Tri-State has large power-generating units that will be forced to sit idle and continue to cost the supplying utility merely due to interconnection of the QF is over-simplified and no longer accurate in today's electric utility market.

FERC Order No. 69 was promulgated in 1980, over a decade before Congress passed the Energy Policy Act of 1992, and 16 years prior to the Commission's first implementation of the Open Access Transmission Tariff under FERC Order No. 888. Prior to this Act, open access to transmission facilities in the wholesale energy markets was extremely limited. As a result, the Commission was rightfully concerned that, absent an open market on which to sell excess power, utilities required to purchase QF power under PURPA could be impacted financially in the face of such obligations and would pass on any additional costs to their customers. In *Carolina*, the Commission explained its rationale for such a rule as balancing "that consideration [of harm against the QF] against the harm of permitting all-requirements customers to purchase directly from QFs and the requirement that the utility and especially its captive customers not be worse off with the QF than without it." 48 FERC at 61,390.

[5] Because Tri-State does not provide tariff sheets on such rates in the public records, Percheron has been unable to review Tri-State's avoided cost rate nor is it at all clear how Tri-State's avoided cost rate may be calculated. Yet, under Tri-State's policy, Tri-State appears to have QFs sell power at Tri-State's avoided cost rate, which in turn is always lower than the average embedded costs of energy and capacity of Tri-State's member cooperatives.

Thirty five years after Order 69 was issued, Tri-State is able to sell on the open market any power that might be displaced by QFs purchasing from Tri-State's REAs. Tri-State, like an investor-owned utility ("IOU"), is free to operate to maximize its return to its owners by the most appropriate use of its assets.[6] As the largest G & T utility in the nation based on miles of owned transmission, and second largest based on operating revenue, Tri State has ready access to open markets to maximize the value of its power, regardless of the impacts of small QF facilities. *See* Petition, p. 7. In its 2013 Annual Report, Tri-State reported that it sold 15.3 million MWh to members out of total energy sales of 18.6 million MWh; this leaves 3.3 million MWh, or over 17% of its sales, after losses, available on the open market. *See Tri-State's 2013 Annual Report*, Exhibit D to Petition, p. 3. Thus, it is a sham to characterize Tri-State and its customers as "captive" for the fixed costs of any minute amounts of power displaced by QFs in this way. *See Carolina,* 48 FERC at 61,390.

Tri-State's ability to easily wheel power to other markets nullifies Order 69's assumption that the supplying utility in an excess capacity situation should in equity be credited for a loss in revenue from QFs by subtracting the estimated lost revenue due to adding QFs on their system from the prices paid to the QF itself. This is not what Congress intended. There is a risk under a narrow interpretation of Order 69 that all revenue losses to huge supplier utilities due to QF power might be charged to the QFs themselves. This would be improper. The intentions of PURPA were to obligate utilities to purchase QF power at rates which are just and reasonable to the *ratepayers* of the utility. The underlying notion of avoided cost is that *ratepayers* shall not be harmed by QF power. In the case of Tri-State, an improper interpretation of Order 69 by the Commission may actually deprive DMEA members and other REA ratepayers of lower priced,

[6] Gone are the days when Tri-State would be considered a small, rural alternative to an IOU. Tri-State controls massive infrastructure and has ability to exercise monopsonistic market power.

more efficient power with less or zero carbon emissions that is available locally from QFs. Because Tri-State's ability to interconnect and wheel power to other markets nullifies the rationale provided in FERC Order No. 69 for prior precedent that an all requirements utility's avoided cost rate is that of the all requirements supplier. New transmission realities and evolving trends toward open access show that earlier interpretations of Order 69 no longer reflect market reality. As a result, a new interpretation of Order 69 in this case is reasonable, just, and fair to all parties.

F. An Order Requiring DMEA to Purchase Power from QFs at Its Avoided Cost or a Negotiated Rate Will Encourage Renewable Development in Colorado, as Congress Intended in Enacting PURPA.

The issuance of a Commission order on DMEA's Petition regarding PURPA is necessary to encourage independent, renewable power in the Colorado. Tri-State's supply contracts currently control some 70% of the area of the State of Colorado alone. If the Commission does not allow DMEA to interconnect directly with a QF and use DMEA's own avoided cost to determine what DMEA will pay Percheron (and other QFs), then QF development over much of the state of Colorado will effectively cease to occur.

Without enforceable, PURPA-based incentives for development of small, independent, renewable power projects in Tri-State service territory, rural communities will not enjoy the associated local economic benefit and ratepayers may be deprived of potentially lower rates that QFs can offer cooperatives of Tri-State. Percheron believes continued development of QF power is a win-win for utilities, ratepayers, and local communities. For example, Percheron's goal with the Drop 2 Project is to successfully demonstrate a new hydroelectric turbine technology in the United States, while providing direct economic benefits to the local irrigation association and construction contractors. When Percheron submitted its Interconnection Request and

Application to DMEA, the letter specifically stated: "Our interest is to work cooperatively with DMEA in determining a rate for purchase of the power that provides benefit to DMEA, its members, and the [Uncompahgre Valley Water Users Associaton], as well as Percheron."

Percheron believes that the DMEA Board, employees, and members sincerely want to encourage local development of clean renewable energy. This can and should be done whenever the cost to DMEA's members (ratepayers) is the same or less from the QF as it is for DMEA to buy their power from Tri-State. In addition to competitive pricing, QFs can offer guaranteed price stability over a long term, unlike wholesale G&T suppliers such as Tri-State.

Additionally, the Commission's interpretation of PURPA in this case has important ramifications with respect to Colorado's continued success in meeting renewable energy goals and developing hydroelectric power. Colorado was one of the first states to enact an aggressive Renewable Portfolio Standard and has been a leader in the country in promoting renewable energy development, and specifically hydro-electric power.[7] In a recent study by the Department of Energy's Idaho National Energy Laboratory, Colorado was ranked as seventh in the nation for hydropower resources, and eighth for remaining new small and low head hydropower potential. *See Figure 16 and 18*, attached as **Exhibit B**. It is easy to see why the citizens of Colorado and the legislature have worked hard to remove barriers to small hydro development in Colorado. It also is clear that the vast hydro potential of the United States is squarely focused on the West, which is the region dominated by large G&Ts such as Tri-State, serving requirements customers who are typically REAs and municipalities.

Absent assurance from the Commission that PURPA requires REAs to purchase QF power, Colorado and other irrigation canal operators across the western United States also risk

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[7] *See* Colorado State Energy Report 2014 pp. 12-13, *available at*: http://www.colorado.gov/cs/Satellite/GovEnergyOffice/CBON/1251597774824 (follow "Colorado State Energy Report 2014" hyperlink) (last viewed March 11, 2015).

being deprived of the recent regulatory and financial benefits of the two U.S. Congressional acts to encourage small hydroelectric power development: The Hydropower Regulatory Efficiency Act (H.R. 267) and the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act (H.R. 678). The American Hydro Association estimates that an additional 5.3 jobs are created for every 1 MW of new hydro capacity developed in the United States. These benefits cannot be realized without the support and underpinning of PURPA for QFs across the West, as requested in DMEA's Petition.

DMEA recognizes the value of its current contract with Tri-State in meeting its electrical needs, but also recognizes its legal obligation under PURPA to encourage development of QFs in its service area. One benefit need not have to come at the expense of the other. Percheron urges the Commission to vigilantly guard against the barriers being used by some wholesale utilities to effectively block development of local renewable resources, and to strengthen the Commission's implementation of PURPA to ensure it remains the backbone for QF development as Congress intended.

G. Expedited Relief Is Appropriate and Necessary.

Finally, Percheron supports DMEA's request for expedited relief on its Petition. Percheron has been working with DMEA on this Drop 2 Project since July 2012, and submitted its formal interconnection application and request to DMEA on September 5, 2014. While DMEA has continued to assure Percheron that there are no real technical, safety, or operating issues with the interconnection, and that DMEA is required to interconnect under Colorado PUC 4 CCR 723-3, no interconnection agreement has been offered to Percheron to date. All the maximum allowed timelines for the interconnecting utility prescribed in Colorado's interconnection rule, Rule 3667 of 4 CCR 723-3, which implement FERC Order No. 2006, have been far exceeded to date.

Percheron commends DMEA for taking this important step in resolving DMEA's obligations to QFs under PURPA. However, Percheron remains gravely concerned about the continued delays. Percheron's Drop 2 Project was planned to be constructed during the current non-irrigation season (Nov 2014 through Mar 2015). However, the Drop 2 plant cannot be constructed until the interconnection agreement is executed. In addition, current contracts with the U.S. Bureau of Reclamation, the Uncompahgre Valley Water Users Association, and the Department of Energy have defined timelines when the plant must be completed and brought on-line, or else Percheron stands to lose its development rights and matching federal funding by the Department of Energy. Percheron and the Department of Energy already have invested more than one million dollars ($1,000,000.00) on this Project. The U.S. Bureau of Reclamation has awarded Percheron the right (under a "Lease of Power Privilege") to construct and operate the Drop 2 Plant. The final design has been completed and approved by Reclamation, competitive bids were solicited, and a local General Contractor has been selected. Because continued delays are adding substantial cost and risk to the Project, the expedited relief on the Petition requested by DMEA is necessary.

WHEREFORE, Percheron respectfully requests that the Commission grants it Motion to Intervene in this proceeding. Percheron also requests that the Commission grant an expedited Declaratory Order, no later than April 16, 2015, stating that (1) DMEA must purchase power generated at the Drop 2 Project and that (2) any purchase must be at least at DMEA's avoided cost rate, including any rate negotiated between DMEA and Percheron.

Respectfully submitted this 11th day of March, 2015

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CERTIFICATE OF SERVICE

I hereby certify that I have this 11th day of March, 2015 caused to be served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by e-service and/or by depositing in the U.S. Mail with first class postage affixed as follows:

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