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Energy Research and Development Division

FINAL PROJECT REPORT

The Amador Water Agency Ione Reservoir Hydropower Project

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

This is the final report for the *Amador Water Agency Ione Reservoir Hydropower Project* (CEC Grant Number EPC-16-037) conducted by the Amador Water Agency. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

Historically, Pelton turbines have been used for in-conduit electric power generation, including secondary applications such as small water districts installing turbines for generation on new or existing water distribution system piping. However, small hydropower projects face major hurdles, including but not limited to high upfront construction costs and low financial returns from power generated. This project endeavored to design and install a small hydropower project with a more efficient Pelton Turbine at the Amador Water Agency's Ione Reservoir. Successful operation of a more efficient turbine could increase production without increasing flow and make this and similar installations more viable. With any small hydropower installation, a small water utility could potentially offset some of its own power usage at other sites and deliver clean power and renewable energy to the statewide electric grid. The goal to improve the economic performance and viability of small hydropower sites was not met due to higher than expected costs to install the system and lower than expected returns from the electricity produced. Lessons learned include using more realistic assumptions during the planning phases for installation costs, electricity generation, and amount of return. Other districts considering these installations can learn from this project by applying more conservative operating assumptions when assessing whether this kind of hydropower can prove a reasonable return on investment.

Keywords: Pelton, hydropower, hydroelectric, water

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Introduction and Background

Hydroelectric power was some of the earliest power generation developed in California; the first commercial hydropower plant was the Redlands Power Plant, which was brought online in 1893 using Pelton water wheels. The Pelton Turbine unit uses a nozzle that directs flow onto the buckets, which spin the Pelton wheel and generate power. Since then, electric utilities in California have created extensive water transportation systems, often in conjunction with dams, to generate power from water flowing downhill through pipes and operating turbines. Although Pelton turbines are still used today, a major hurdle with small hydropower projects is that the costs to design and construct the project are significant, especially in comparison with relatively small revenues. This leads to many missed opportunities to generate power from water transportation systems.

According to the American Society for Civil Engineers 2021 Infrastructure Report Card, the "nation's drinking water infrastructure system is made up of 2.2 million miles of underground pipes." Similarly to commercial hydropower facilities where pipes have been constructed to move water to a turbine for power generation, drinking water system pipelines could potentially be used for hydroelectric power generation if conditions are adequate. Approximately 62 megawatts (MW) of power is currently generated in California by these small hydropower systems, however, research suggests that the potential generating capacity for the State from these types of installations is as much as 250 MW. Bringing more of these projects online will contribute toward California's renewable energy goals.

Commercial hydroelectric plants generally consist of simple and direct piping that conveys water from a higher elevation reservoir to the powerhouse, which is solely designed to operate the powerhouse turbines. Conversely, few if any drinking or raw water suppliers designed their systems with hydropower in mind. While a water district's pipelines are already in place, a retrofit of those facilities is still required to install a hydropower generation unit and this may not be feasible in many locations. Where an installation would not impede the primary goal of providing drinking or irrigation water and has adequate pressure and flow, there is still the upfront cost associated with design and construction of such an installation. Finally, while commercial hydropower projects are located on rivers that may have hundreds to even tens of thousands of cubic feet per second of water flow, the transmission pipelines in drinking water systems may only convey tens of cubic feet per second or less. Less flow equals less power generated, less revenue and longer rates of return.

Potential installation locations are limited by State requirements for drinking water, electrical and instrumentation control requirements, and the need for excess pressure. This type of project involving installation on a pipeline with ample pressure and the ability to discharge into a reservoir is likely the simplest and easiest installation for a small hydropower project. While the Amador Water Agency (Agency) has two such pipelines, some districts would not have any similar simple installations. The fact that the installations are not widespread also contributes to lack of proliferation. If a water purveyor could visit the adjacent district and see a successful installation, it would appear less risky than it might in light of the previous points.

Project Purpose

The Agency was formed in 1959 to provide water and wastewater services to the residents of Amador County, in northern California, which has a 2020 population of 40,474 people. The Agency currently provides retail service to a population of approximately 13,868 people through 6,511 retail residential water service connections.

The Agency treats and delivers untreated and potable water to residents of Amador County, from various elevations as high as 3,700 feet to as low as about 400 feet. This is accomplished through extensive systems of tanks, pipelines and six water treatment plants. While pressure is reduced for residential service throughout much of the system, there are dedicated transmission pipelines that operate at high pressure and could be used for power generation. For this small hydro project the Agency selected the Ione Pipeline, which moves water from the Tanner Reservoir to the Ione Water Treatment Plant.

The Ione hydropower project included design and installation of a Pelton turbine and generation unit on the Ione Pipeline and exploring if efficiency gains in these turbines could be achieved. A major hurdle with small hydropower projects is that the costs to design and construct the project are significant, especially in comparison with relatively small revenues once the units begin operating at these lower flow rates. These factors can extend the date upon which the project begins paying for itself so far into the future that the project may not make financial sense. If the turbine efficiency could be increased, the return on initial expenditures for design, material purchases, labor and installation could be achieved sooner and potentially make this and similar projects financially viable.

The team explored if the more efficient turbine could generate approximately 72,000 Megawatt hours (MWh) of renewable energy with the milestone to reduce greenhouse gas emissions by 50,650 metric tons (MT) of carbon dioxide equivalent (CO2e), both over a 50-year asset life.

Project Approach

The Agency contracted with consultant NLine Energy to complete the CEC funding applications, project management, project design, engineering, construction management and completion report. NLine and the Agency worked with Gilkes, a hydropower turbine and pump manufacturer, who completed the efficiency studies and manufactured the Pelton unit placed into service at the Ione Reservoir. Gilkes engineers completed significant calculation and modeling to maximize the turbine efficiency for the Ione Project. Prior to delivery of the final turbine and generator to the site, Gilkes built a scaled test rig to compare an existing design with the improved design. Central Sierra Electric was responsible for the installation at the demonstration site and Bailey Civil Engineering performed analysis and wrote the final report.

As with many projects during COVID, there were some delays and challenges in installation and start-up. Other non-COVID-19 related construction delays occurred previously and a significant design flaw in the turbine also delayed production generation at the facility but was addressed with a manufacturer re-design of the problem part.

Project Results

According to Gilkes Turbine Design Report prepared for this project, the project goal of designing a more efficient Pelton turbine unit was met. Optimization of the geometry at the nozzle and wheel buckets, reduced losses which increased efficiency of the unit. The report also noted that efficiency would be maintained at even higher than expected maximum flows and efficiency could increase at lower flows. As this installation may not run at maximum flows, the increase in efficiency at lower flows was welcome. The scale test unit that Gilkes built and tested was noted to demonstrate improved efficiency over the original standard unit. Gilkes Turbine Design Report details the specifics of that work and claims that by year 12 of operation, the design turbine will produce one additional years' worth of energy compared to the original equipment. However, the goal to improve the economic performance and viability of small hydropower sites was not met. The higher than expected costs to install the system and the lower than expected returns from the electricity produced have resulted in this project not being economically viable. Hopefully, the lessons learned from this project can help other water agencies avoid the same mistakes.

The operation, starting in March 2021 and throughout 2021, had an average turbine production between 200 and 250 kW, which corresponds to 84-85 percent efficiency. During the months with consistent operation, total production was usually between 30,000 and 45,000 kilowatt hours (kWh) or 30-45 MWh, although the installation was able to produce nearly 80,000 kWh (80 MWh) in May 2021 and actual efficiencies of 87-89 percent were realized at these higher flow rates. This was expected to see the best efficiency at the highest flow rates and lower efficiency at lower flow rates. Actual efficiencies, however, averaged 1-3 percent lower than projected. The team believes this is because the efficiency projections were from the turbine manufacturer, and did not include electrical system losses such as line and transformer losses.

The team found that the system causes additional aeration at the reservoir causing bacteria growth resulting in taste and odor problems at the Ione Water Treatment Plant. This is an ongoing problem in the summer months and likely has no functional solution without a design modification to the system.

Lessons Learned The most important lesson from this project is that multiple unrealistic assumptions were made during the planning phase of the project. Had realistic generation returns and construction cost been factored into the analysis originally, the project may have proceeded differently or not at all. The issues are not with this type of project, the issues are with preliminary work on this specific project.

The team recommends to other districts considering these installations that they are conservative with their operating assumptions when assessing whether this kind of hydropower can prove a reasonable return on investment. While it may be tempting to look at the highest power buyback rates available and highest flows possible during a project pre-design analysis, it does not make sense for any district considering a similar project to be optimistic about buyback rates, flow rates, operational capability and operational timing.

Across-the-board conservative estimates should be used to ensure project operation stays within realistic estimates and provide districts with a clear picture of project financials. For this project, Pacific Gas and Electric Company buyback rates used in preliminary analyses were higher than actual buyback rates. Actual construction costs were significantly higher than projected in pre-project analysis.

The initial cost of the units and cost of installation on existing systems versus return in power generation buybacks will remain the main hurdle to install more of these units. If a significant number of units are purchased, the unit cost would be expected to decrease, however it may not be enough for such installations to be financially viable. It's feasible that some locations may be better suited to installation due to existing piping configurations that may make installation easier and, therefore, more cost effective. A new transmission pipeline, designed from the ground up to include hydropower unit installation, would be expected to achieve significant cost savings since new construction properly designed is nearly always more cost effective than construction retrofitting. Installations with higher flow rates and greater pressures will allow for larger turbines and provide for greater generation capacity.

Each district considering a similar installation must perform a site-specific analysis to determine if the initial investment will meet their district's acceptable rate of return. For the Agency, current power buyback rates ranged from $.05675/kWh to $.18136/kWh so the return on their initial investment may be much longer for similar low flow installations. For areas where buyback rates are higher or flows allow for greater generation, a faster return on initial investment may be achieved, making a similar project desirable.

Advancing the Research to Market and Sharing the Knowledge

Widespread market adoption may be unlikely as the turbine and generation units require specific site conditions to be cost-effective. The Agency presented project information to other water districts at the Association of California Water Agencies before actual project costs or results were known. It is also possible this project may prove to dissuade some other small districts from pursuing this type of project because of the difficulties encountered, but hopefully the lessons learned throughout this project and detailed in this report can assist other districts in making the best decision for them.

Gilkes will likely use the increased efficiencies in future models of their Pelton turbine generation units, which would provide some of the increased efficiencies developed during this project to other districts who may contract with Gilkes for their own projects. Gilkes position in the hydropower market should provide an opportunity for marketing reach of improved efficiencies, which could attract potential buyers to the technology. Competitors to Gilkes would be expected to achieve similar efficiencies with their own products.

The target markets for this technology in California are other water districts that have existing or future planned pipelines where power generation could potentially benefit them and their ratepayers. Due to the myriad factors related to determining whether a similar project is appropriate for a given location, the size of the target market is difficult to determine. Additional grant funding may be necessary to increase interest and installation of these smaller scale systems.

Benefits to California

When water districts are able to achieve a swift return on the initial investment associated with retrofitting hydrogeneration units to existing pipelines, future net positive income generated could benefit ratepayers. Income from hydropower generation could be applied to system upgrades (leading to a more reliable water system), which are likely needed in nearly every district in the State, or will be in the future. Should a water district receive enough income from hydrogeneration once the initial expenditures are covered, it is possible that rate increases could be delayed, which benefits ratepayers.

The Ione project showed efficiencies as high as 87-89 percent, total production was between 30,000 and 80,000 kilowatt hours (kWh) per month or 30-80 MWh per month. This generated an income of up to $8,000 per month.

Due to the complexities of these installations and the variety of conditions at different sites, quantifying economic or societal benefits to ratepayers would be difficult to estimate generically for the State as a whole. Hydropower has the potential benefit of power generation at peak times when other renewables are not available, for example the State's investments in solar power cannot assist with power demands at night but hydropower can be generated around the clock or during times of peak electric demand. Retrofits of existing drinking water system pipelines with hydropower generation have potential to provide power to the grid when other renewables cannot.

CHAPTER 1: Introduction

District Background

The Amador Water Agency (Agency) was formed in 1959 to provide water and wastewater services to the residents of Amador County, which has a 2020 population of 40,474 people. The Agency currently provides retail service to a population of approximately 13,868 people through 6,511 retail residential water service connections.

The Agency operates four general service areas: the Amador Water System (AWS), the Central Amador Water Project (CAWP) System, La Mel Heights, and Lake Camanche Village. The AWS is where facilities for this hydropower project are located and the other service areas do not apply to this project.

The Amador Water Agency is the main water purveyor for residential and commercial use in Amador County and has the legal jurisdiction to serve water throughout Amador County. The Agency's primary source of water is the Mokelumne River watershed which supplies the primary water systems of the AWS and the CAWP. There are a total of 6,933 water service connections in the Agency's service area, not including wholesale entity customers and their customer connections.

The AWS was formerly owned and operated by Pacific Gas and Electric Company (PG&E) and currently covers more 450 square miles and serves the communities of Amador City, Ione, Sutter Creek, Sutter Hill, Martell, and their vicinities, portions of Ridge Road and New York Ranch Road and the wholesale communities of Jackson, Plymouth and Drytown. The Agency has two water treatment plants at Sutter Hill and Ione, which receive water from the Mokelumne River via Lake Tabeaud and transmission pipelines. The AWS delivery system consists of approximately 167 miles of water piping for potable water customers and an additional 24 miles of conveyance canals for untreated water customers. Further specific information about service zones and use can be found in the most current version of the Agency's Urban Water Management Plan.

Portions of the Agency's system are more than 100 years old and the system is very extensive, considering the relatively small number of customers. Many system components are past their serviceable lifetime but self-funding component replacements with a small customer base is difficult and grant funding can also be difficult to obtain. Any potential additional revenue source must be considered and in-conduit hydropower facilities are one of the few potential revenue sources available apart from normal rates.

Project Background

The Amador Transmission Pipeline supplies raw water to the Tanner Reservoir and the Tanner Water Treatment Plant. In 2016 a hydropower facility using the Amador Transmission Pipeline was put into operation at the Tanner Reservoir.

The Tanner Reservoir feeds the Ione Reservoir via the Ione Pipeline and subsequently the Ione Water Treatment Plant. The Ione Reservoir holds 26.9 acre-feet when full. The Ione

Water Treatment Plant has a maximum day treatment capacity of 4.7 cubic feet per second (cfs). An expansion to the treatment plant and an upgrade to the backwash system is currently being designed.

The Ione Pipeline was completed in 1987 to transport water from the Tanner Reservoir to the Ione Reservoir. The Ione Pipeline begins at the Tanner Reservoir and extends approximately 7.5 miles to its terminus at the Pressure Reducing Station (PRS) adjacent to the Ione Reservoir. The Ione Pipeline is a 16-inch ductile iron pipe. The pipeline has a maximum capacity of approximately 13 cfs based on the hydraulic profile shown on the as-built plans. According to data supplied by the Agency, current flow rates between the Tanner Reservoir and the Ione Reservoir vary during normal operation between approximately 1 cfs and 5 cfs. The as-built plans and operational knowledge indicate the static pressure at the Ione Reservoir pressure reducing station is approximately 550 pounds per square inch (psi). Pressure is reduced there to approximately 50 psi.

A pipeline that provides service to the Preston School diverts water from the high-pressure side of the PRS to another PRS that supplies enough pressure to this service line. This pipeline provides supplemental water supply to the Ione water treatment plant.

Flow leaving the Ione PRS enters the Ione Reservoir at three different locations in order to prevent short circuiting and stagnation in the reservoir. When water leaves the new hydroelectric station, it is at atmospheric pressure instead of its current 50 psi used to fill the Ione Reservoir. The new hydroelectric station will be set high enough above the reservoir elevation to provide the necessary pressure to supply the existing reservoir inlets.

Flow into the Ione Reservoir is currently set manually by the Agency operations staff at the PRS. The flow rate set point is dependent on the change in reservoir level from the previous day, projections of water demand for the current day, and operator experience. There is no remote communication link between the Ione Water Treatment Plant or the Tanner Water Treatment Plant with the Ione Reservoir. Flow rate leaving the Ione Reservoir is set manually by a flow control valve located at the Ione water treatment plant based on demand. An aerial view of the project vicinity is shown in Figure 1. The new site plan for the project is included in Appendix A.

Preliminary Analysis

A preliminary analysis of the Ione Hydropower Project was completed by NLine Energy in January 2013. This analysis estimated that installing a 247 kilowatts (kW) hydropower station at the Ione Reservoir would cost $1,648,680, could produce 1.56 million kilowatt hours (kWh) annually, return $123,220 annually, provide 30 year gross savings of $4,505,249 and would pay for itself in 14.9 years. Based on this report and subsequent evaluations, the Agency elected to pursue grant funding and after receiving the CEC grant, moved forward with the project.

After multiple analysis iterations and bidding the project, in July 2018 NLine Energy estimated the project, now a 447 kW hydropower station, could produce 1.38 million kWh annually, could return $216,000 annually, would cost $2,917,000 to construct, with net earnings of $5,092,000 and a payback of 11.6 years. While the annual production appears to be inconsistent with the size of the unit compared to the original analysis, it is unclear why, and it was based on this latter report that the Agency elected to proceed with project construction.

Figure 1: Project Aerial

Electric equipment and transformer in top center, new hydroelectric powerhouse top upper right, lone reservoir in bottom right quarter with dam at bottom center

Source: Amador Water Agency file photo

CHAPTER 2: Project Approach

Preliminary Work and Permitting

NLine Energy was contracted with by the Agency to produce a preliminary design report for the Ione Hydropower Project in 2013. Additionally, NLine completed work on the previously installed Tanner Hydropower installation. The Agency again used NLine's services for design and construction of this Ione Hydropower project.

NLine Energy contracted with EN2 Resources Inc. to complete the environmental documents for the project beginning in 2014. The comment period for the project environmental impact statement/mitigated negative declaration was noticed in the Amador Ledger Dispatch and occurred from August 12, 2016 to September 11, 2016. The Final Initial Study/Mitigated Negative Declaration was dated September 22, 2016 and was assigned State Clearinghouse Number 2016608037.

The Amador Water Agency ultimately contracted with EN2 Resources Inc. directly in 2018 to complete environmental permitting work and construction phase surveys for the project. This included the Army Corps of Engineers Section 404 nationwide permit, the California Regional Water Quality Control Board 401 Water Quality Certification, the California Department of Fish and Wildlife Section 1602 streambed alteration notification, field survey and report, the stormwater construction permit, the wetland delineation field survey and report and the preconstruction bird survey and report.

Early December 2017, NLine Energy solicited Geocon Consultants Inc. to complete the geotechnical investigation for the project. Geocon delivered the final investigation report on January 24, 2018.

Contracts

The Amador Water Agency directly contracted with:

- Gilkes for design, manufacture and delivery of the turbine.
- NLine Energy for preliminary estimates, project planning, CEC funding applications, CEC grant management, project design, engineering, construction management and general project oversight.
- Central Sierra Electric as prime contractor for construction of the project. Campbell Construction was the underground subcontractor.
- EN2 Resources for construction phase environmental permits and surveys for the project.
- JSP Automation for electrical start up and commissioning support.
- Laminar Energy for startup commissioning and operational support.
- Flow Science for a pipeline and turbine pressure surge analysis.

Turbine Design and Manufacturing

NLine Energy solicited hydroelectric specialists Gilbert Gilkes & Gordon Ltd (Gilkes) to complete design and manufacturing of the turbine, which they did during the design and construction phases of the project. A Pelton turbine had been selected for the project due to the sites high head and low flows, with which Pelton turbines excel. Gilkes noted Pelton turbine efficiency in general is above 90 percent but believed they could meet the project goals of improving efficiency by 1-1.5 percent by improving the injector and runner designs. The Pelton turbine is similar to any waterwheel. Water is directed at buckets or runners attached to a wheel (Figure 2). The wheel spins and when coupled with a generator is able to produce electricity. The injector is the nozzle through which water is accelerated and focused on the runners. The runners "catch" the water and spin the wheel. A detailed schematic is found in the turbine design report completed by Gilkes. Gilkes undertook computation fluid dynamics modeling to optimize the injector and runner designs, which found theoretically an approximately 1 percent increase in energy production could be achieved. Gilkes then built a scaled test rig and were able to validate the efficiency gains that were shown to be able to be achieved in modeling. Further detail can be found in the 2018 Turbine Design Report, attached in Appendix B.

Figure 2: Pelton Turbine Buckets

Source: Amador Water Agency file photo

Design and Construction of Project

Project Design

NLine Energy teamed with Domenichelli and Associates to complete civil engineering construction plans and specifications for the project. They hired EETS, Inc. to complete the electrical engineering portion of the design. Final plans for construction were signed by the Agency as approved on October 1, 2018.

Prior to the project the Agency owned a 16.5 acre property around and including the Ione Reservoir. In April of 2016, the Agency acquired an additional 13 acre parcel west of their existing parcel. The main construction work would take place on the Agency's original parcel. This simplified the siting of the work as the connections to the existing Ione Pipeline and the new powerhouse building construction were able to be placed on existing Agency property with no property or easement constraints related to facility locations. The new parcel was helpful for site access and connections to PG&E facilities. Proximity of the existing Ione Pipeline to the reservoir minimized the linear footage of new pipeline that would need to be installed to connect the existing Ione Pipeline to the new turbine and generator, which would be located in a new powerhouse building. Some easements were required for ultimate access and facility electrical connections, which acquisition was completed during the design phase of the project.

The project design included cutting into the existing 16" transmission line above an existing pressure reducing station to install a new 12" pipeline bypass and valves to the new powerhouse building. A new flowmeter was specified downstream of the existing pressure reducing station. A new 19'4" x 30'4" metal powerhouse building to house the new Pelton turbine and generator was specified. New discharge piping was designed from the powerhouse building to the Ione Reservoir. A new transformer pad was specified for placement of a new PG&E transformer, as well as new electrical distribution line to connect to the closest PG&E facilities, approximately 1/3 mile away. Site grading, road improvements and additional electrical work and civil and electrical appurtenances were designed and specified as required to make the project operational. The conformed project plans and specifications more completely detail the work completed on the project.

The Agency terminated the agreement for services with N-Line Energy in December 2019, prior to project completion and startup. The Agency completed the project, including startup and commissioning.

Project Construction

Site clearing work commenced in mid-December 2018. Preliminary project work continued through early January with site preparation and clearing and utility potholing.

On January 8, 2019 the underground contractor (Campbell Construction) began trenching and installing conduit for new electrical lines. Trenching and some potholing continued for the intermittently throughout the rest of winter. The Contractor was often offsite due to inclement weather preventing work. In early April 2019 work recommenced fulltime with concrete formwork related to the transformer pad and powerhouse building including additional underslab underground work.

In early July the new transformer was set and the building erection commenced. By early September 2019 site work and building were mostly complete and the site had been turned over to electrical work, completed by Central Sierra Electric, the prime contractor. Electrical work continued until early October, at which time Campbell remobilized to complete new pipeline installations and connections to the existing system as well as final electrical underground work. They worked on these items through November 2019.

Beginning December, 2019 through January 2020 the Contractors were onsite only intermittently to complete final tie-in items and some running punchlist items. Ultimately, the construction schedule increased by approximately one year due to contractor chosen means and methods, design flaws and field changes made during construction that had far reaching effects. This was a significant extension to the time by which the project was expected to be completed. Some of the material delivery and field change delays are fairly normal during any construction project and are to be expected. However, some of the field changes were so significant that a key subcontractor refused to continue on the project due to liability concerns. That and contractor scheduling problems should have been avoidable with better project management and control of design and construction changes.

Commissioning of Project

Due to the COVID-19 pandemic and other delays, startup operations were delayed until fall of 2020 and continued through summer 2021. Another significant delay was that Gilkes, a British company, headquartered in the United Kingdom, was required to be onsite for the startup to not void the unit warranty. For most of 2020, the Gilkes representative was not able to be onsite because of travel restrictions. Once travel restrictions were relaxed, the representative was required to quarantine for 14 days at the start and end of the trip, costs to be borne by the Agency, so the pandemic precluded their availability onsite for a significant time. Eventually, Laminar Energy was hired to complete startup operations and Gilkes was able to be involved via teleconference and determined that installation and startup were acceptable.

The Amador Water Agency is within Pacific Gas and Electric's service area and they had to approve and inspect the electrical connections to their system. COVID-19 and internal PG&E delays resulted in approximately six months delay related to connecting to the electric grid.

Because Amador Water Agency staff did not have experience operating this type of hydrogeneration unit, third parties conducted startup and operational training. If Agency staff had more experience operating similar units, consultant startup and training costs could have been reduced.

Final testing and check out with Tesco Controls and Laminar Energy began November 10, 2020. PG&E tested and approved the equipment on December 10 and on December 14 unit operation began (Figure 3). On December 14, within hours of initial production startup, high vibrations and temperatures in the turbine bearings were noted and the manufacturer (Gilkes) was contacted. From mid-December through February 17, the Agency worked with the manufacturer to troubleshoot and the unit was only operated for short periods, mostly less than an hour and related to troubleshooting the bearing problem. On March 24, 2021 Gilkes decided that the unit could be operated with elevated vibration and temperatures without causing damage to the unit. Starting in early April the unit began to log more significant hours. On May 25, after several procurement and administrative delays, new bearings based on manufacturer re-design, were installed, which resolved the temperature and vibration issues and the unit ran normally.

An initial concern of the project was discharge of the turbine outflow into the reservoir aerating the reservoir and causing algae growth or other undesirable side effects. The Agency has previously (since 2017) had taste and odor issues at the reservoir in summer months. This was not addressed in the project design and the problem was again realized in mid-June 2021 with taste and odor problems at the Ione treatment plant. Geosmin at the Ione Reservoir was determined to be the cause of the foul taste and odor. Any discharge from the turbine to the reservoir was aerating the reservoir, causing turnover and contributing to the taste and odor issues in the drinking water. The easiest and most definitive resolution was to turn the hydroelectric unit off, stop drawing water out of the reservoir and send water from the Ione transmission pipeline directly to the plant.

Figure 3: Ione Hydropower Station

Gilkes Pelton Wheel Turbine, generator and electrical equipment inside new powerhouse building at Ione Reservoir.

Source: Amador Water Agency file photo

CHAPTER 3: Project Results

Project Analysis

PG&E revised rate schedules in late 2020/early 2021 and sent the Agency information requiring them to select their rate tier. The actual electric rates received were significantly less attractive than the planned rates which the original project financials and return on investment were based.

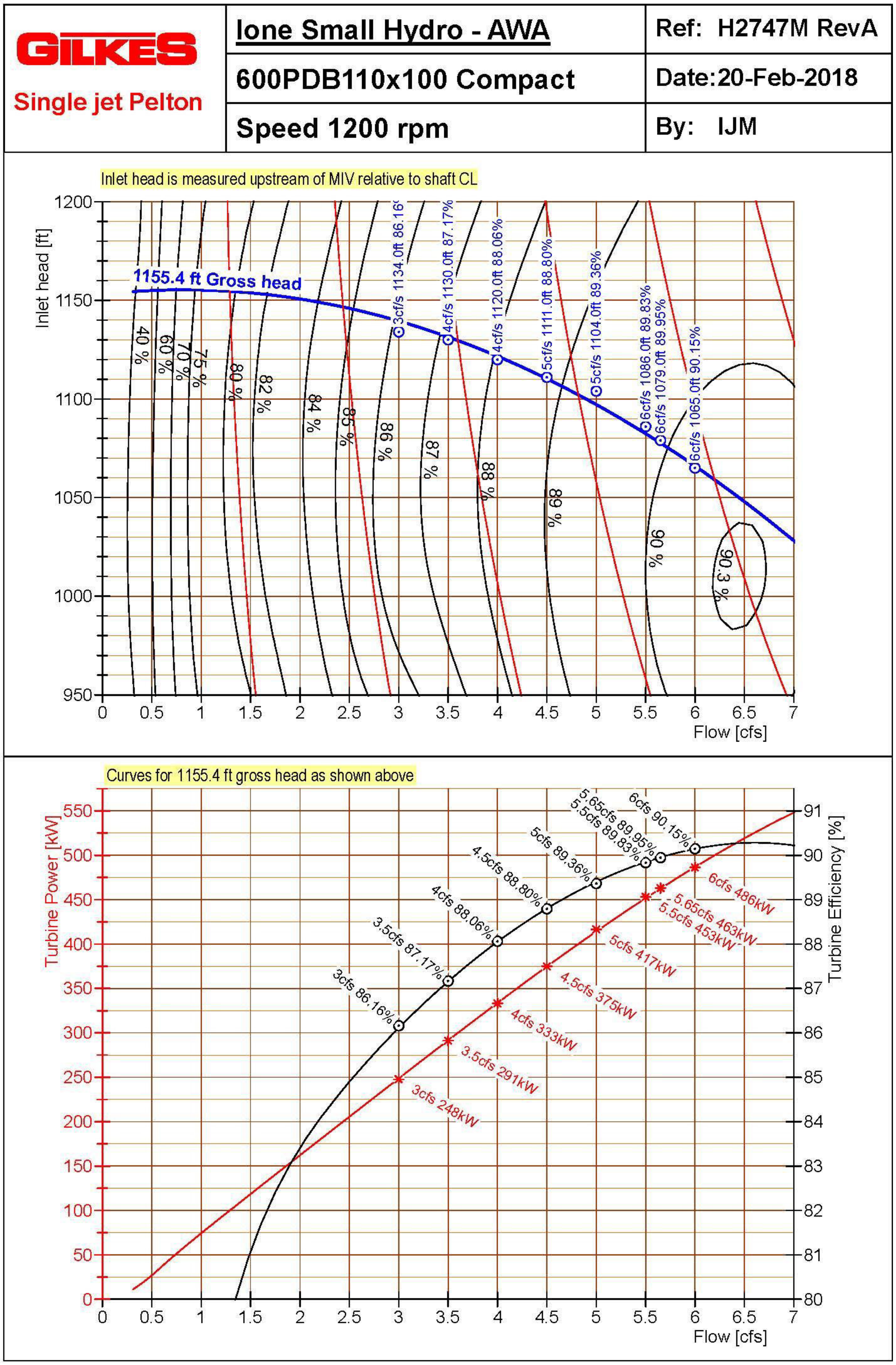
Bailey Civil Engineering completed an analysis using measured actual power produced and the PG&E calculated power buyback rates. Agency staff had measured 408 kW of generation at a maximum flow rate of 5.65 cubic feet per second. This is approximately 2 percent lower efficiency than what was projected by Gilkes. Consistently throughout 2021, efficiencies were 1-3 percent below what was projected by Gilkes. Those projected efficiencies are the black curve in the lower graph in Figure 4. It is currently unknown exactly where the losses are but it is unlikely Gilkes would have factored transformer and line losses into their analysis and expected that the Figure 4 numbers are an isolated turbine theoretical maximum. As the curve shows, efficiencies are best at high flow rates (more than 90 percent at 6 cfs), but at the Agency's lowest generation rates of ~2 cfs, efficiency at best is ~83.5 percent. At the 200-250 kW generation averages, real turbine efficiency at this installation is 84-85 percent, although in April and May, efficiencies were between 87 percent and 89 percent at times. Significant water storage capacity is not available at the Ione Reservoir, therefore the maximum flow for power generation has to equal the treatment plant demand for that day. However, there is an outlet from the Ione Reservoir to the Ione Treatment Plant so higher flow rates could be used during peak hours with the Ione Reservoir used as a surge tank.

Seven scenarios were analyzed:

1. 24 hours per day, seven days per week generation.
2. Generation while the treatment plant is operating at plant flow rates.
3. Generation during normal staff hours seven days a week.
4. Generation during normal staff hours five days a week.
5. Generation at maximum flow rates during peak hours only.
6. Generation at maximum flow rates during peak and partial peak hours.
7. Generation at maximum flow rates for the maximum hours to match average plant flow rates for the day.

The Agency's pre-project design scenario was scenario 7, to generate at maximum flow rates for the maximum amount of time to match plant demand during peak and partial peak hours especially. Under these scenarios, the maximum expected revenue by analysis was scenario 7, with potential for about $183,000 in generation revenue per year. Scenario 6, which could prove more operationally viable as it focused generation on a narrower time frame during only peak and partial peak hours, was analyzed to have potential to generate about $131,000 per year.

Figure 4: Gilkes Projected Generation Curve



Gilkes Generation Curve.

Source: Amador Water Agency files

Project Operational Data to Date

Approximate actual electric rates and electricity production for 2021 are tabulated in Table 1 and Table 2. Production is approximate due to occasional data recording issues. The numbers are slightly lower than actual, but no more than a few percent. By mid-June 2021 the unit's aeration of the Ione Reservoir was creating significant taste and odor issues due to geosmin production so the unit was not operated. The unit only operated a handful of maintenance hours in July and August of 2021. Some production resumed in September and October of 2021, however the 12KV fuses failed on November 7, 2021 for unknown reasons and new fuses will not ship until mid-March 2022 due to the ongoing supply chain problems.

Table 1: Actual 2021 PG&E Buyback Rates (B-1 Schedule)

Time-Of-Use	Hours	Rate
Summer Peak	4:00 PM - 9:00 PM	$0.17054
Summer Partial-Peak	2:00 PM - 4:00 PM & 9:00PM - 11:00 PM	$0.12131
Summer Off-Peak	All Other Hours	$0.10050
Winter Peak	4:00 PM – 9:00 PM	$0.11529
Winter Super Off Peak	9:00 AM – 2:00 PM	$0.09917
Winter Off Peak	All Other Hours	$0.08275

Source: Amador Water Agency

Table 2: 2021 Actual Production

Month	Total Hours	Peak Rate Hrs.	Total kWh	Average kW
April	126	20	44,636	358
May	321	105	78,886	246
June	209	73	42,385	203
September	84	53	17,100	204
October	133	50	32,765	246
Total	873	301	215,772	

Source: Amador Water Agency

The production noted was mostly during daylight hours, often during off peak times. One day in April 2021 was able to average 405 kW, however, due to the difficulties in matching treatment plant rates and lack of programming with the unit, most production kW was significantly lower. Production in May and June of 2021 may have been close to optimal, with long run times that ran through peak and partial-peak hours. However, the summer buyback rates only apply from June 1–September 30. By comparison, May 2021 generated about $8,000 in revenue and June 2021 generated about $6,000 in revenue while operating significantly fewer hours than in May 2021.

The 2013 analysis for the Ione Hydropower Project completed by NLine Energy estimated installation of a 247 kW hydropower station at the Ione Reservoir would cost $1,648,680, produce 1.56 million kWh annually, return $123,220 annually, provide 30 year gross savings of $4,505,249 and would pay for itself in 14.9 years.

The July 2018 NLine Energy analysis estimated the Ione Hydropower Project, now a 447 kW hydropower station, could produce 1.38 million kWh annually, could return $216,000 annually, would cost $2,917,000 to construct, with net earnings of $5,092,000 and a payback of 11.6 years.

While the 2021 actual production is not representative of the entirety of a normal production year due to the design problems and noted equipment failures, the months it did operate are likely indicative of what can be normally expected. The higher construction costs means that even if the estimated production kW were achieved, the project would take longer to pay for itself. The first year's actual production suggests that the estimated $216,000 yearly return was also very optimistic to the point of unrealistic. The estimate may have been achieved by assuming unrealistic water volumes could be run through the turbine and higher electrical rates than could be obtained. Based on the more realistic operating schedule undertaken in 2021, the actual realized yearly returns from power sold are likely $60,000-90,000 if the unit can operate during summer in the future and more likely $40,000-60,000 if it cannot operate during summer months when buyback rates are highest. This even further extends the date for which the project can pay for itself. Once equipment end of life replacement costs are factored in due to normal wear and tear, the project may not be able to pay for itself at all. Ultimately, when project costs are twice what was originally estimated and power generated may be less than half what was originally estimated, 1 percent gains in turbine efficiency become insignificant. An objective of the project was to produce 72,000 Megawatt hours (MWh) over the fifty-year asset life of the equipment which would result in a greenhouse gas emission reduction of 50,650 metric tons (MT) of carbon dioxide equivalent (CO_2e). If the data from May 2021 (which had the highest production rate during testing) was assumed for year-round operation, the production over the fifty-year life would only be about 47,000 MWh with a reduction of about 33,000 MT CO_2e. This would be a best case scenario and is only about 65 percent of the expected results.

The maximum theoretical power for the Ione Reservoir turbine according to NLine and Gilkes is 570kW at a flow rate of 6 cubic feet per second. As evidenced, lower flow rates, which are common for this pipeline, will result in lower power generation. Generation flow rates were consistently between 2.5 and 4 cfs during operation, although during April the Agency was able to achieve generation at 5-6 cfs. The Ione Pipeline was built to convey raw water for treatment and the flows conveyed are normally dependent on customer demand; significantly higher in the summer months and lower in the winter. While the project design and construction costs are known, the power generation should be dependent on flow rates that can be achieved without interfering in normal operations. Should flow rates for generation be desired that are higher than customer demand, the ultimate maximum flows will become dependent on reservoir capacity since the treatment plant would not receive the entirety of flows conveyed in the pipeline and this may limit maximum flows. Pacific Gas and Electric has multiple power buyback rates, depending on demand expectations and other factors. The buyback rates that were assumed in pre-design were higher than the actual buyback rates PG&E is providing at this time. Ideally, a maximum amount of power would be generated during the peak rate times of 4 pm to 9 pm, however the Agency does not normally staff operators during that period. All these factors will prove to be an ongoing challenge with operation of the unit and only after a significant time of unit operation, likely several years or more, will the Agency be able to determine how the unit operation and returns are functioning.

CHAPTER 4: Technology/Knowledge/Market Transfer Activities

Public Outreach

The Agency presented project information to other water districts at an Association of California Water Agencies semi-annual conference before actual project costs or results were known. No other papers have been published on the project.

Widespread market adoption may be unlikely as the turbine and generation units require specific site conditions to be cost-effective. Water districts interested in implementing this technology would need to perform site specific analyses to determine if similar installations could prove beneficial to them. The Agency presented information about this project to other water districts at the Association of California Water Agencies before actual project costs or results were known. It is also possible this project may prove to dissuade some other small districts from pursuing this type of project due to the difficulties encountered, but hopefully the lessons learned throughout this project and detailed in this report can prevent other districts from making similar mistakes.

Gilkes will likely use the increased efficiencies in future models of their Pelton turbine generation units, which would provide some of the increased efficiencies developed during this project to other districts who may contract with Gilkes for their own projects. Gilkes position in the hydropower market should provide an opportunity for marketing reach of improved efficiencies, which could attract potential buyers to the technology. Competitors to Gilkes would be expected to need to achieve similar efficiencies with their own products.

The target markets for this technology in California are other water districts that have existing or future planned pipelines where power generation could potentially benefit them and their ratepayers. Due to the myriad factors related to determining whether a similar project is appropriate for a given location, the size of the target market is difficult to determine. Additional grant funding may be necessary to increase interest and installation of these smaller scale systems.

CHAPTER 5: Conclusions/Recommendations

Consideration of Project

Small community water districts similar to the Amador Water Agency, with extensive lists of aging infrastructure and limited replacement capital, have to consider any and all options for additional revenue. Hydropower is one of the few potential options for additional revenue beyond customer rates. For locations with excess water pressure, significant water volumes and potential for simplified and cost-effective initial facility construction, the return on construction investment could be rapid enough to prove a financial benefit. For locations at lower pressures where head loss may affect other operations or locations where flows are not enough to generate significant revenue, projects may not pay for themselves quickly enough to prove worthwhile. It must also be understood that these additional facilities suffer from the same liabilities that other water system infrastructure does: it has a limited lifetime at the end of which it will require replacement at additional cost. Replacement cost must be figured into a long-term analysis to determine if a similar project can generate revenue for a district.

The majority of the water districts in the state have old and aging facilities (such as pipelines, treatment facilities, pumps) that need replacement now or should be scheduled for replacement soon. Thousands of feet of pipeline can be replaced for the same cost as one of these small hydropower generation units. Additionally, interruption of normal operations, inadequate flows and pressures and adding further complexity to the already complex infrastructure associated with providing customers clean drinking water must be weighed fairly by a district considering such a project to ensure responsible budgeting and planning.

Lessons Learned

Pre-Project

Unrealistic assumptions were made prior to the project. These included assuming the pipeline and turbine would be able to operate at peak efficiency and maximum flow rates at all times and that the installation would be able to operate nearly continuously. The power buyback rates assumed were faulty, yet these assumed buyback rates were used in all calculations. Very high flow rates were assumed to maximize generation in analysis, however at those flow rates the pressure drop in the pipeline is severe enough there is not enough pressure to operate the turbine. The 2.5-4 cfs that the unit consistently operated at during 2021 is operationally viable in conjunction with the treatment plant and all analysis should have been based on that, rather than assuming the Agency would be able to flow the day's water system demand directly into the reservoir at 5.6 – 6 cfs, year-round, which is unrealistic.

The initial project cost estimate was $1.6 million; however the final construction cost was more than $3.5 million. This significantly alters return on initial investment date and the determination of whether the project is feasible.

Construction

The Agency's project manager allowed multiple field changes to the plans requested by the site contractor, apparently without consideration to other trades on the project. This eventually resulted in an electrical subcontractor refusing to work due to liability concerns, resulting in more delays. This could have been avoided if the construction plans did not require changes, if unnecessary changes were not allowed, and if necessary work changes had been completed formally, with opportunity to comment for all parties involved.

The site contractor was inconsistent in their mobilization and completion of work onsite for unknown reasons, which resulted in delays that could have been avoided with stricter project management. While delays of this sort are certainly not desirable, no cost time delays and time delays with minor additional cost will not render a project inviable. This project did not cost more than twice the estimates because of change orders. The actual bid construction costs were significantly greater than the estimates because the original estimates were unrealistic. The requests for changes to the work can also be tied to pre-project work. A well-designed project has little need for field changes. All these construction problems can be addressed by contracting with experienced designers and construction managers.

Design and Operation

The original operation of the Ione pipeline allowed for discharge into the reservoir or a direct feed to the treatment plant bypassing the reservoir. For operation with discharge into the reservoir, three smaller outlets fed into the reservoir at different locations to provide circulation and aeration in the reservoir. The Agency questioned whether a higher flow operational scheme with the turbine installed would cause issues and evidently the design engineers did not believe higher flow out of the turbine would change anything. The turbine installation was designed similarly, to be able to bypass the reservoir and feed the plant directly or discharge directly into the reservoir. The original intent was to flow a maximum amount of water during peak rate hours for maximum electric generation, using the reservoir as a surge tank with significant fluctuation in volume. The turbine and generation plant were designed to run at a setpoint, not fluctuate with water treatment plant rates, which fluctuate based on customer demand. As noted previously, additional programming and controls, beyond the scope of this project, would be needed for the flow through the turbine to fluctuate and match the plant rate. Without those controls in place, there is little alternative but to discharge the turbine outlet into the reservoir.

In summer of 2021, the increased temperatures coupled with higher aeration and flows into the reservoir during generation operations were causing significant bacteria growth. The geosmin produced was causing such severe taste and odor problems at the plant and in the system that the Agency had little choice but to stop generation until lower demands and cooler temperatures returned in the fall because the operational affect was too severe. There is a piping configuration that allows discharge from the power plant into the bottom of the reservoir, which has been used some, but at high flows with maximum power generation, even this causes de-stratification and bacteria growth in the reservoir.

The installation was brought online December 14, 2020. That same day it became obvious there was a problem with the main bearing, as the unit was overheating and prone to violent shutdown after a few hours of operation. This was determined by the manufacturer (Gilkes) to be a design flaw. Gilkes did determine it was safe to operate the unit at the higher temperatures, but during the bearing re-design and supply process, the Agency operated the unit only during hours when staff was available to monitor the unit, significantly reducing production. Gilkes did redesign and replace the bearing at their own cost, but it was not until May 25, 2021 that the new bearing was onsite and installed after several procurement and administrative delays.

The controls strategy for the unit was not designed for automatic operation, or to match water treatment plant flows, which is required if the Agency cannot use the Ione Reservoir; for example during the summer peak flows with Geosmin. Resolution will require a revised programming and control strategy for the installation, with associated cost, so that it can be operated to match plant demands. This also means the unit will often operate at reduced, less efficient flows and at off peak energy times, both of which are major financial benefit reductions. This will greatly extend the time to return on initial investment.

Recommendations

Project Analysis

The most important item to be aware of and address if considering a similar project is performing as accurate and inclusive a project cost benefit analysis as possible. It makes sense to provide significant conservatism in the analysis, such that if the conservative analysis still shows the project is viable then the district can be sure to realize the gains estimated and should the completed installation outperform the analysis, the district will realize net positive revenue at an earlier date. Any unfounded optimism in the analysis could leave a district with a project that breaks even over time or worse, saddles a district with a negative revenue projection, as this project does.

It may be tempting to think that a small hydropower system could be installed on an appropriate pipeline and a district will simply be able to turn it on, start making money and walk away. Understand this is unrealistic and system maintenance and operation must be figured into any pre-project analysis.

The team strongly recommends that a water district's own staff perform initial analysis of the project. Each district understands best what they serve to potentially gain and what their operational realities and capabilities are. Third parties are likely to be most interested in the work they will benefit from during the project, such as design or project management work. They will not necessarily be motivated to be as invested in the short- or long-term viability of the district's projects, revenue and liabilities as the district itself.

Alternately, if a district could enter into a contract with a third party who completed all phases of project design, management and construction and delivered a turnkey installation for a fixed price known to the district in advance, that could be a way to reduce risk and achieve a set goal for revenue and return.

For currently unknown reasons, the estimates of power generation from Gilkes were higher than the proven generation once the project was brought online. Based on the history of the project design and review of the analysis available, it is questionable whether electric, motor, transmission line and transformer losses were included in the original analysis, which could also result in lower-than-expected output at no fault of the turbine manufacturer. On a small project such as this, these losses could significantly affect the analysis. The variance in these numbers could prove critical whether a project is worthwhile or not and it is strongly recommended that a district not only perform or confirm a complete analysis is performed with respect to anything that will affect the final product but contact other operators of similar systems to help establish a baseline for what real world generation returns can be achieved.

Revenue Analysis

PG&E's power buyback rate structures vary significantly. For this project, the buyback for their super off-peak winter rate timeframe is only $0.08275 per KWh and the buyback rate for off peak winter is only $0.09917 per kWh. These two rates are in place for 19 hours each day from October 1 to May 31. The current peak summer buyback rate of $0.17054 per kWh is only in place from June 1 to September 30 between 4 pm and 9 pm. Generally, the hours when a water distribution or treatment operator is likely to be at work are off peak hours. Should a district have hydrogeneration operators or wish to add them, this may offer additional flexibility for the hours that the powerhouse can be operated. Should the district desire to assign generation duties to normal operators, this must be factored in the initial analysis as this could affect the possible revenue from the installation. Should the installation be able to be run mostly remotely or self-sufficiently, operator working hours may be of no consequence. Even if an in-conduit hydropower station is able to be operated during peak hours or for extended periods, each district must ensure the actual PG&E buyback rates are utilized in the analysis, as these are significantly lower than PG&E charge rates.

CHAPTER 6: Benefits to Ratepayers

Ratepayer Benefit Summary

The majority of the water districts in the State have old and aging facilities including pipelines, treatment facilities and pumps that need replacement now or should be scheduled for replacement soon. When a water districts customers cannot provide the revenue required for the necessary system replacements and upgrades, such as with the Amador Water Agency, any alternative sources of revenue will help the district operate. Hydropower can provide an alternative source of revenue if conditions are such that the hydropower project can achieve a swift return on the initial investment associated with retrofitting the hydrogeneration unit to existing pipelines. Additional revenue can lead to a more reliable water system by paying for needed system upgrades and replacements. Another benefit to ratepayers is that it could help delay rate increases and save them money.

Statewide Electric Grid Reliability

California's electric grid has had reliability issues in recent years. This is due to many factors but one is the prevalence of solar power and that solar power is only available during the day. Hydropower can supply the grid anytime water can flow and even these small hydropower projects can potentially help meet demand in nighttime hours. This Ione project often generated power in nighttime hours in 2021. It must be noted that small hydropower projects would be expected to have some of the dirty power issues that residential rooftop solar has but it is still providing power and additional supply during nighttime hours that may offset cleanliness problems. Additionally, these are projects on existing or necessary pipelines so they do not have the environmental impact a new dam and commercial hydropower installation would.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
Agency	Amador Water Agency
AWS	Amador Water System
CAWP	Central Amador Water Project
CEC	California Energy Commission
cfs	Cubic feet per second
CO2e	Carbon dioxide equivalent
Geosmin	A volatile, organic compound ($C_{12}H_{22}O$) that is formed especially by soil-dwelling bacteria and aquatic cyanobacteria and that may impart a disagreeable, musty taste and odor to drinking water
kW	Kilowatts
kWh	Kilowatt hours
MT	Metric tons
MW	Megawatt
MWh	Megawatt hours
Pelton Wheel	An impulse turbine or waterwheel consisting of a row of cup shaped buckets arranged around the rim of the wheel and actuated by one or more jets of water playing into the cups at high velocity
PG&E	Pacific Gas and Electric Company
PRS	Pressure Reducing Station
psi	Pounds per square inch

REFERENCES

Delplanque, Jean-Pierre, Aubryn, Cooperman; Sukhpreet, Mann. 2017. Renewable Energy Resource, Technology, and Economic Assessments; Appendix L – Task 12: Technical Assessment of In-Conduit Small Hydro Power Technologies. CEC-500-2017-007-APL. California Energy Commission.

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