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ADDENDUM
Via E-Mail
DATE: September 23, 2022

Contract 22-C-00040; Renewable Energy Initiatives Design-Build

Submitters on the above referenced project are hereby notified that the following addendum is made to the RFQ. SUBMITTED PDFs SHALL CONFORM TO THIS NOTICE.

Item 1: Attached for reference is a copy of the Hydroelectric Generation and Energy Recovery Proof of Concept Study Technical Memorandum.

All other provisions of the RFQ not in conflict with this Addendum shall remain in full force and effect. Questions are to be e-mailed to Contract Administration@tampagov.net.

Jim Greiner

Jim Greiner, P.E., Contract Management Supervisor

Prepared for:

City of Tampa Florida

Hydroelectric Generation and Energy Recovery Proof-of-Concept Study

Technical Memorandum

Submitted by:

Gannett Fleming

*Excellence Delivered **As Promised***

Gannett Fleming Project Number 066775

City of Tampa Contract No. 18-D-48824

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July 2020

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Executive Summary

The City of Tampa is identifying opportunities to enhance utilization of renewable energy at their water resources and distribution facilities. Two concepts for possible renewable energy have been evaluated and are documented within this Memorandum: 1) the integration of a small hydropower generation system at the Hillsborough River Dam (HRD), and 2) energy recovery opportunities at the Interbay Ground Storage Tank and Re-pumping Station (RPS). The City of Tampa contracted with Gannett Fleming to develop a Proof of Concept evaluation of these two sites.

The conceptual evaluation for the HRD considered siting constraints and impacts to the existing dam, available technologies, flow duration curves and available net head, interconnection locations, constructability and maintenance, planning level cost-benefit analysis, and regulatory considerations. The conceptual evaluation for the RPS facility considered available technologies and the ability for integration without detriment to facility performance. A phased approach is recommended to move forward from concept to implementation with further screening and developing detailed design features.

Hillsborough River Dam Options

A variety of hydroelectric generation options were considered for this location. Gannett Fleming reviewed the dam configuration and operation for siting options, prepared flow-duration curves, reviewed possible generator designs, reviewed energy demands of the nearby David L. Tippin Water Treatment Plant (DLTWTP) and Solids Processing Facility (SPF), and electrical interconnection options.

As a result of the review process, the following two options were further evaluated including the preparation of design concepts:

1) Siphon-style design installed at the left (south) non-overflow portion of the concrete dam; and
2) Crossflow generating unit installed at the downstream end of the Low Flow Outlet (LFO) conduit.

A third configuration includes combining the higher-capacity siphon-style units with the lower-capacity crossflow unit to further increase power generating capacity by providing generating options through a larger range of the flow-duration curve.

Interbay Ground Storage Tank and Re-pumping Station Options

Gannett Fleming investigated several options for installing a generating unit at the RPS using energy available in the main water supply line to the large ground storage tank. Two locations were identified as suitable for a small generator. The proposed unit would be connected to the existing electrical supply equipment at the site and would act as an additional power supply. The power generated would help offset some of the energy required to run the facility.

Gannett Fleming determined a Pump As Turbine (PAT) configuration would be the best option for this facility. A PAT is a pump connected to a motor which is electrically configured to perform as a turbine-generator pair. This energy recovery concept is common for facilities with relatively small flows and low pressures.

Electrical Interconnection Options

It appears that the best opportunity to electrically connect the proposed HRD generating units would be a parallel interconnection with the Tampa Electric (TECO) electrical feed at the SPF or the DLTWTP to use the energy generated and reduce the energy supplied by TECO. This will require an Interconnection

Agreement with TECO, and the electrical design will need to comply with TECO's requirements. Interconnection at the SPF is considered less costly than an interconnection at the DLTWTP due to the proximity of the SPF and compatibility with the SPF 480 V power supply (vs. the 13.2 kV DLTWTP power supply). Additionally, interconnection at the SPF is expected to result in periods of excess generation due to the expected seasonal high flows within the river and the seasonal operation of the SPF. Excess energy would be delivered to TECO and applied to future electric utility bills for up to 12 months based on the interconnection agreement. Interconnection at the DLTWTP is considered more costly than an interconnection at the SPF; however, due to the large energy demand of the DLTWTP, excess energy generation is not expected, maximizing direct use of the available generation.

At the RPS, it appears the best connection option is a parallel interconnection with the TECO electrical feed at the facility. The unit will act as an additional supply source for the RPS energy requirements, reducing the consumption of energy provided by TECO. This connection option is recommended as the water availability and flow at the RPS are more consistent throughout the year, as compared to flows at the HRD.

Financial Considerations

For the HRD site based on the siphon-style "proof of concept", we estimate the construction costs could be in the range of $1.2M to $2M. For the Interbay RPS site based on the pump-as-turbine style "proof of concept", we estimate the construction costs are approximately $550,000. The payback period for the HRD ranges from 20 to 26 years, and the RPS payback period ranges from 10 to 14 years, depending on the options, estimated construction prices, and cost of electricity.

A variety of funding assistance and incentive options may be available and are described briefly in the memorandum. These include Business Energy Investment Tax Credit programs and Renewable Energy Incentive Programs such as Florida's Renewable Generation Net Metering Incentive Program. There are also Renewable Energy Loan Programs through the US Department of Energy.

Next Steps

Should the City decide to pursue generation options at either location, Gannett Fleming recommends a phased approach in the development of these projects. Recommended items for the next phase may include: 1) begin conversations with TECO and evaluate their detailed requirements for interconnection under Florida's Renewable Generation Net Metering Incentive Program; 2) prepare a basis-of-design, 15% design, and updated cost estimate; 3) perform a desktop permitting assessment; and 4) evaluate project delivery options (e.g. Design Bid Build, Design Build, Construction Manager at Risk, Engineer Procure Construct, etc.).

Following successful completion and outcome of these activities, the City can decide which delivery method to pursue, which will inform the successive contracts. Depending on the City's preferences, this could be a separate Engineering Design contract followed by a Construction Contract; a Design Build (DB) contract; or possibly an Engineering, Procurement, Construct (EPC) contract. Gannett Fleming can support the City with any of these options.

1.0 Project Overview

1.1 Authority

Gannett Fleming (GF) has performed the work documented within this technical memorandum under Work Order 24 of City of Tampa Contract No. 18-D-48824, executed on 10 March 2020.

1.2 Objectives

The City of Tampa is identifying opportunities to enhance utilization of renewable energy at their water resources and distribution facilities. Two concepts for possible renewable energy have been evaluated and are documented within this memo: 1) the integration of a small hydropower generation system at Hillsborough River Dam (HRD), and 2) energy recovery features for the the Interbay Ground Storage Tank and Re-Pumping Station (RPS).

The conceptual evaluation for the HRD considers evaluating engineering features and requirements, constructability and planning level cost benefit analysis, and regulatory and permitting considerations. The conceptual evaluation for the Interbay facility considers available technologies and ability for integration without detriment to facility performance. A phased approach is recommended to move forward from concept to implementation for further screening and developing detailed design features.

1.3 Project Location

The two locations evaluated for this study are shown in Figure 1, below.

1.4 Previous Studies and Reports

- Report on the Hillsborough Hydroelectric Power Plant, September 7, 1920 (1)
- Report Upon Water Situation Created by Failure of Tampa Electric Company Dam on the Hillsborough River, February 17, 1934 (2)

Gannett Fleming

Project Vicinity and Location Map
Figure 1

2.0 Hillsborough River Dam Small Hydropower Evaluation

This portion of the study investigates the viability of installing a new hydropower generating facility at the HRD and considers possible options for using that energy to support the power requirements of the David L. Tippin Water Treatment Plant (DLTWTP) and a nearby Solids Processing Facility (SPF). The HRD site historically generated hydroelectric power between 1896 and 1933 from a hydropower plant that operated at the site's previous timber crib dam before a record flood destroyed the facility in 1933 (3). The HRD was reconstructed in the 1940's establishing the reservoir which, among other uses, is a water source for the DLTWTP.

2.1 Flow Duration Curves (from flow data)

Flow duration curves are developed to estimate flow and associated statistical exceedance values at the Hillsborough River Dam based on historic values of mean daily flow (MDF) rates for a gage located at the dam (USGS 02304500 Gage Hillsborough River Near Tampa FL). Gage data was downloaded from the USGS website (4) for the period of record between 1938-10-01 and 2019-10-01. Flow-duration curves (5) were developed in accordance with the equations below where m is the ranking, from highest to lowest, of daily mean flows for the specified period of record; and n is the total number of daily mean flows.

$$Frequency\ (F) = 1 - \frac{m}{(n+1)}$$

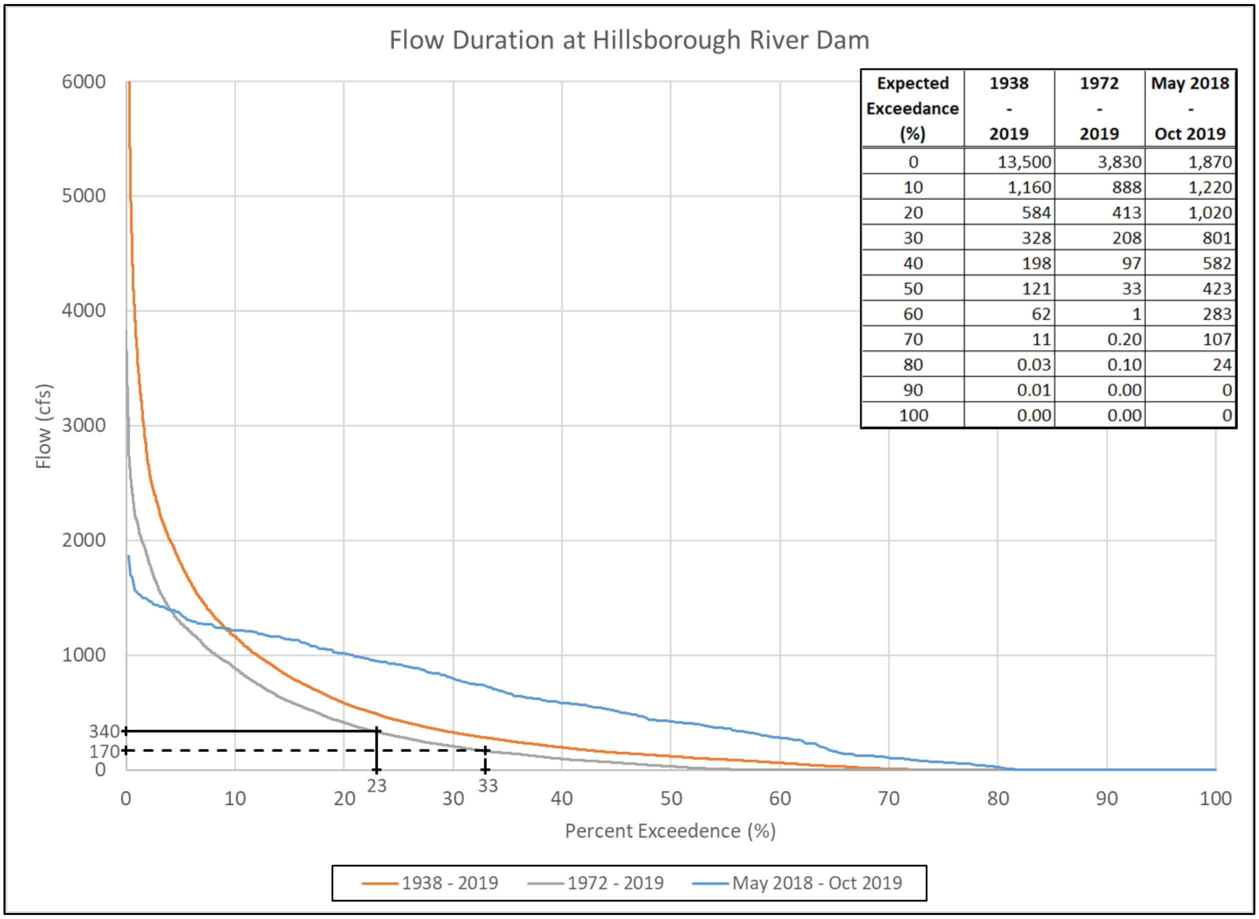
$$Duration\ (D) = \frac{m}{n}$$

This analysis relates average annual stream flow to its expected probability of exceedance. No areal adjustments are made because the data reflects river flows as the dam. The measured mean daily flow rates are assumed to be consistent with gate release flows given the limited flood storage volumes available in the reservoir.

As a result of flood control and water management changes over the years, water flowing to the HRD is influenced by canals, bypass levees, springs and the DLTWTP intake. Additionally, 2007 legislation to hydrate the Lower Hillsborough River (downstream of the HRD) requires minimum releases at the dam of 20 cubic feet per second (cfs) from July 1 through March 31 and 24 cfs from April 1 through June 30 to help manage salinity levels below the HRD (6).

To help evaluate the changing conditions, the flow estimates developed for this study are divided into three time periods. The initial time period is from 1938 to October 2019 which includes the full range of available flow data, the second time period includes available flow data from 1972 to October 2019 to capture presumed changes in water management infrastructure and a significant population increase of the area between the 1950s and 1960s, and the third time period includes available flow data from May 2018 to October 2019. While the third time period is too short to use for a representative flow duration analysis, there is a noticeable flow increase which could be influenced by the legislated minimum flows and the increased rainfall which occurred in the Tampa area during this period compared to the average annual precipitation.

Regarding the legislated minimum flows, it may be reasonable to assume a flow of 20 cfs would be met or exceeded close to 100% of the time assuming the Low Flow Outlet (LFO) is discharging; however, the flow duration curve based on 2018 – 2019 flow data indicates that a flow of 20 cfs would be met or exceeded 80.5% of the time, while the flow of 24 cfs would be met or exceeded 78.6% of the time. This discrepancy could be influenced by the use of other sources to meet the legislated minimum flows (such as springs, sinks and bypasses downstream of the USGS gage) and the corresponding operation of the LFO. The flow duration curve based on 1972 – 2019 flow data indicates that a flow of 20 cfs would be met or exceeded 52% of the time, while the flow of 24 cfs would be met or exceeded 51.2% of the time.



Expected Exceedance (%)	1938 - 2019	1972 - 2019	May 2018 - Oct 2019
0	13,500	3,830	1,870
10	1,160	888	1,220
20	584	413	1,020
30	328	208	801
40	198	97	582
50	121	33	423
60	62	1	283
70	11	0.20	107
80	0.03	0.10	24
90	0.01	0.00	0
100	0.00	0.00	0

Figure 2 – Flow-Duration Curves Downstream of Hillsborough River Dam

2.2 Gross and Net Head Estimates

The gross head available for a hydro generation facility is defined as the difference in elevation between the upstream water level and the downstream water level. The net head available for generation is a lesser value that accounts for the reduction in the generation system capacity related to head losses resulting from configuration changes, such as valves, gates, bends, expansions or contractions in the hydro plant inlet and outlet piping.

The Hillsborough River Dam has a top of dam elevation of 29 feet above National Geodetic Vertical Datum of 1929 (NGVD29)) and the normal pool elevation is 22.5 feet NGVD29. Depending on the inflow and downstream demand, flow from the dam is released using two low-crest radial gates (North and South); six high-crest gates situated between the low-crest radial gates; nine fixed crest spill walls; and/or a small slide gate at the LFO located near the left abutment. Because the use of the radial gate sections for power generation would require significant modifications to the dam and would impact their spilling capacity, the existing LFO and non-overflow section are considered the most feasible locations for a new power generating system.

Most hydro turbine generator designs require the outlet of the turbine to be submerged in order to prevent excessive vibration and cavitation within the turbine. The required submergence varies with the design type and size of the turbine generator. Given the current configuration of the structure downstream of the dam, it appears that a discharge tailwater pool would be required to create the necessary downstream submergence for any turbine generator designs which utilize the LFO, whether they were mounted upstream or downstream of the dam.

The LFO includes a 16-inch-wide by 24-inch-tall slide gate which discharges through the dam by way of a 36-inch diameter pipe. The invert of this pipe is approximately at elevation 7 feet MSL, meaning the top of discharge with the slide gate fully open would be near elevation 10 feet MSL. It is reasonable to expect that the power generator discharge pool surface elevation would need to be approximately one foot above the top of the discharge, or at 11 feet MSL. Thus, the difference in water surface elevation between the upstream and downstream pools would be approximately 11.5 feet. For any design concepts using the LFO as the water discharge point, this value should be used as the available gross head. It is reasonable to expect the net head to be approximately 90% of the gross head, or approximately 10.4 feet.

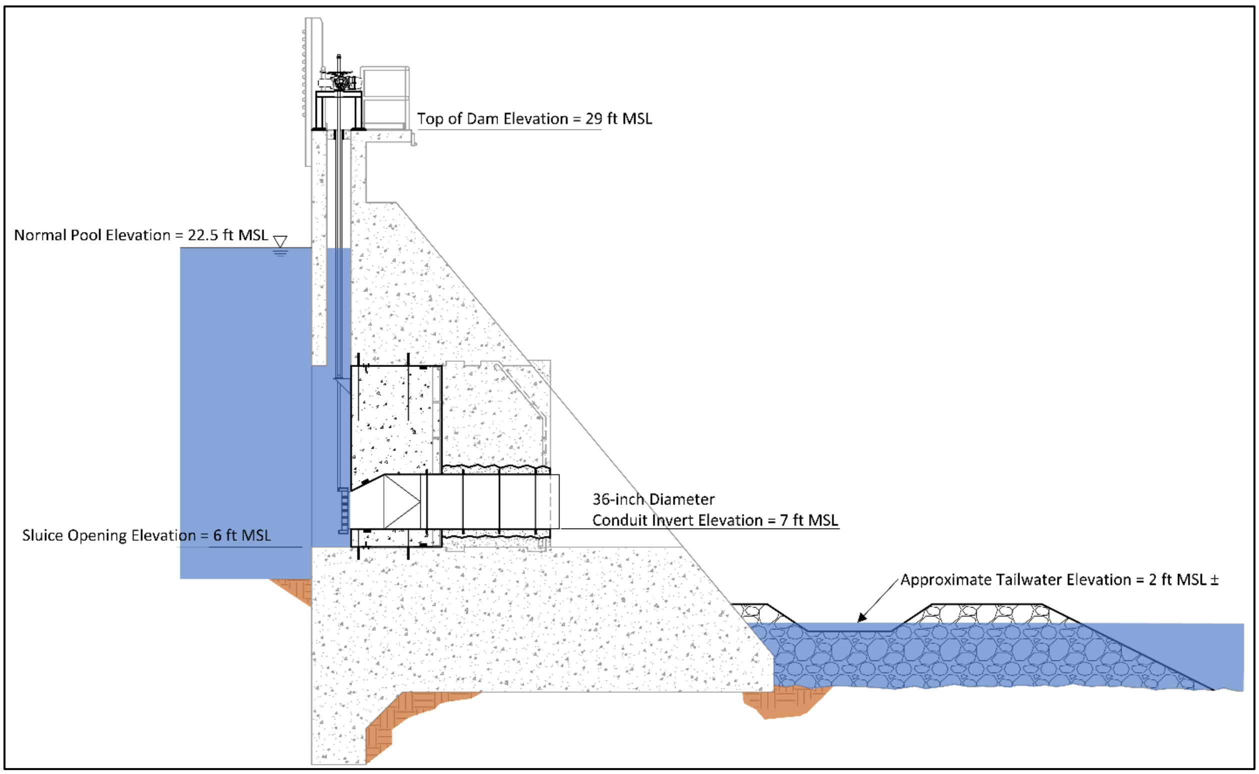


Figure 3 – Basic Configuration of Low Flow Outlet

In addition to turbine designs which could be installed at the LFO, there are small hydro turbine generator designs which operate using a siphon arrangement over the top of the dam. This could allow a greater differential head to be used for the turbine generator. Assuming the downstream water surface elevation is approximately 2 feet MSL, the gross head available for a siphon-type design would be approximately 20.5 feet. However, the siphon style designs tend to be less efficient than Kaplan (bulb-style) designs, and thus the net head for this type of configuration could be estimated at approximately 75% of the gross head, or approximately 15.4 feet.

For the purposes of this report, the net head of 15.4 feet was used for projecting possible power availability and energy production from generators with a siphon-type design.

Siphon design projects are limited by the elevation change between the upstream water level and the top of the siphon. The existing HRD elevation difference between the normal pool elevation and the top of the dam warrants a notch or penetration in the top of the dam which would effectively lower the top of the siphon to a more acceptable level. The existing top-of-dam elevation would be retained at 29 feet MSL.

2.3 Hydroelectric Turbine Design Options

A variety of turbine design and configuration options were screened for this study; however, this study only discusses packaged-type units that are compatible with the available head and flow regime found at HRD. A list of potential manufacturers which were evaluated and supporting marketing materials are included in Appendix A.

Several manufacturers build bulb-style Kaplan turbine designs. The bulb style is a feasible option and would require modifications to the dam when compared to other options described below. The bulb turbine design would be either fully submerged on the upstream side of the dam, such as the Andritz HydroMatrix or Voith Stream Diver design, or installed in a structure on the downstream side, which would allow access to the equipment from the top and sides. Both design approaches would require the use of a crane (either permanent or portable) to install and remove the equipment for maintenance. Installing a bulb-style Kaplan turbine either on the upstream or downstream side of the LFO could result in a viable installation from a technical perspective, but the added civil construction costs may be significant if the installation were built on the downstream side of the dam.

Ossberger builds a crossflow turbine which could be installed on the downstream side of the dam at the LFO. These machines are relatively simple in design and have few moving parts. They can handle a wide range of flows and are typically installed as run-of-river type hydro plants. The capacity of the Ossberger crossflow machine would be similar to the other LFO type design options but may possibly run for longer periods of time due to the wider flow range in which they can operate.

Another design option for the downstream side of the LFO would be a vertical shaft turbine generator system manufactured by Flygt. The design is similar to a submersible pump style of construction. This design would consist of a combined turbine generator on a single vertical shaft, assembled as a single unit which would be lowered into a mounting structure immediately downstream of the LFO discharge tunnel. The mounting structure would consist of an extension of the LFO pipe into a structure which would direct the horizontal inflow into the turbine and discharge the water vertically into a discharge pool similar to the other LFO options noted earlier.

A third option for HRD would be a siphon-style design, such as the Mavel TM-10, which could result in less costly construction and fewer impacts to the downstream side of the dam structure and appurtenances, while maximizing the potential available head. Placing a siphon-style installation over the top of the dam would require: 1) modifications to the conduit system which crosses the dam at the walkway level, 2) a modification to the top section of the dam structure to allow the siphon arrangement to be installed with a shorter suction line on the upstream side of the dam, and 3) the modification of the walkway structure to maintain access to the dam and allow for maintenance of the new turbine generator. It appears that two or more siphon systems could be installed over the left end section of the concrete dam. Maintenance of a siphon-type design could be performed with a portable crane.

2.4 Hydroelectric Plant Sizing Options

The flow-duration curves discussed in Section 2.1 were used to develop potential power plant sizes, which were then compared to the electrical energy consumption information provided by the City for both the DLTWTP and the Solids Processing Facility (SPF). It appears that the present electrical requirements for the SPF more closely match the possible power generation design options at the dam than do the current power requirements of the DLTWTP.

Table 1 – SPF Demand Charges and Energy Consumption for 2019

Month	Average Daily Demand (kW)	Energy (kWh)	Average Daily Use (kWh)	Billing
January	290	93,200	3,006	$ 8,480.36
February	290	89,280	3,189	$ 8,286.08
March	285	89,440	2,885	$ 8,615.53
April	241	76,320	2,544	$ 7,328.45
May	233	80,960	2,612	$ 7,481.60
June	277	94,160	3,139	$ 8,773.08
July	302	109,920	3,546	$ 9,962.11
August	307	113,440	3,659	$ 10,220.20
September	306	99,680	3,323	$ 9,449.05
October	290	96,720	3,120	$ 9,080.81
November	293	93,040	3,101	$ 8,916.48
December	280	85,840	2,769	$ 5,743.09
	Total Consumption:	**1,122,000**	**Total Billings:**	**$ 102,336.84**
	Average Monthly:	**93,500**		

Notes:

1. Ideal new plant configuration would have the following characteristics:
   a. Capacity would meet the experienced Demand (kW) for the SPF, i.e. greater than 325 kW.
   b. Output would exceed the monthly energy consumption of the SPF.
   c. Monthly historical energy + demand charges would be greater than the debt service required for the new facility.
   d. Thus, the plant will need to be designed with a net output of greater than 325 kW and a Capacity Factor of greater than 43%.
2. This data was provided by City of Tampa and reflects the power and energy consumption data shown on monthly billings from Tampa Electric for consumption at the SPF in 2019.

The maximum flow capability of the LFO at the normal pool elevation of 22.5 feet is 53 cfs. With this flow and the net head for the LFO of 10.4 feet, as discussed earlier, the maximum generating capability of a machine installed at the LFO would be approximately 35 kW. Assuming this flow can be maintained through the LFO, the plant could provide 35 kW to the SPF for approximately five and a half months per year. This does not meet the desired need completely but could potentially provide up to 158,000 kWh per year. This could offset approximately 14% of the annual energy costs for the SPF. If the minimum flows mandated to be released at the HRD are used as the flow through the LFO (20 cfs and 24 cfs) the generating capability of the proposed facility would be reduced as shown in Table 2.

Table 2 – Flow and Generation via the Low Flow Outlet (Annual)

Duration (Months)	Flow (cfs)	Exceedance (% of year)	Capacity (kW)	Energy (kWh, rounded)
6 months	20	52	15	67,000
6 months	24	51	18	79,000
~5.5 months	53	46	35	158,000

A second design option is to use a siphon-style hydro generator design, installed over the top of the dam. Because these units would not be restricted by the flow capacity of the LFO, they could generate more energy and possibly reduce the demand charges at the SPF for a portion of the year.

The Mavel TM-10 unit mentioned above has the capability to handle up to 170 cfs, and with a design net head of 15.4 feet, could deliver approximately 160 kW for about four months per year. A second unit installed adjacent to the first unit could provide additional energy for two to three months. These two units could provide enough energy to meet the load of the SPF for three months per year, and approximately half the energy requirement for up to two additional months per year. The two units together could feasibly generate 839,000 kWh per year. Both scenarios would require flows substantially in excess of the minimum mandated flows.

Table 3 – Flow and Generation via Siphon-Style Generators (Annual)

Configuration	Flow (cfs)	Exceedance (% of year)	Capacity (kW)	Energy (kWh, rounded)
1 Unit	170	33	171	494,000
2 Units	340	23	342	839,000

As can be seen from Table 3, the combination of two siphon units could provide more than half the annual power needs of the SPF. However, the energy will not be provided throughout the year, but only for about three to four months of the year, as flows of 340 cfs are not available all year.

2.5 Grid/Plant Interconnection Options

Gannett Fleming reviewed the electrical design of both the DLTWTP and the SPF to evaluate viable interconnection locations of the new hydro generator(s) into the electrical system. The incoming plant voltage at the SPF is 480 V, while the DLTWTP operates with an incoming voltage of 13.2 kV. Conceptual interconnection options are depicted on Figure 4, below.

Small generating units, as considered here, are most cost effective if the generating voltage is relatively low. This results in smaller packages and lighter units, which can reduce the installation cost via reduced material for foundations and structural supports. Generator options considered in this study typically operate at an output voltage of 480 V. Thus, it would be reasonable to expect that a connection to the SPF would require no additional transformer, as the generating voltage could be the same as that used in the plant. In addition, as the SPF is relatively close to the proposed location for the new hydro unit, the power could be supplied to the SPF via a short 480 V power line.

A connection to the DLTWTP would require the addition of a transformer to step the generated voltage of 480 V up to 13.2 kV. The transformer output would be connected to the DLTWTP via a dedicated 13.2 kV transmission line and terminate at the electrical connection at the DLTWTP with a disconnect switch.

The connection point for a new hydro generator would be approximately 1,700 feet from the SPF, and approximately 4,200 feet from the DLTWTP. In combination with the interface voltages noted above, it appears that the better choice for the electrical connection would be to the SPF at 480 V. This would reduce the installation capital costs by avoiding the cost of a longer transmission line to the DLTWTP as well as the cost of a step-up transformer at the new hydro site to increase the generated voltage to 13.2 kV. In addition, if the interconnection to the DLTWTP is used, there could be a negative impact from the transmission line losses, which can amount to 5% – 8% of the available energy. In general, transmission line electrical losses can be minimized by increasing the transmission voltage, but in this case any improvement could be offset by the added costs related to the step-up transformer and cost of the line structure itself, i.e. bigger insulators for higher voltage levels, etc. Interconnection options reviewed are the following:

1. Alternate/Backup Power Supply to the SPF: The new hydro generator could be added to the existing SPF electrical bus in a manner similar to that used for the emergency generator electrical connection, with appropriate transfer switches and synchronizing capability. It would be necessary to include appropriate switches to isolate the TECO connection, similar to the Automatic Transfer Switches (ATSs) currently installed at both facilities for the existing emergency generators. The hydro plant would act as an alternate supply, similar to the existing emergency generator, and the ATS transfer power supply to TECO if the hydro units are not available. Since the SPF electrical consumption is seasonal with varying operational shifts, operating in this alternate supply mode will require the new hydro generator system to start and stop each day. This will accelerate wear and tear on some of the new plant components as compared to starting and stopping once per week or even less frequently, as would occur if the electrical loading were more consistent. This option is not recommended.

2. Alternate/Backup Power Supply to a portion of the DLTWTP: If the interconnection were made to the DLTWTP, the incremental energy provided by the new hydro generator would not meet the total plant need. By isolating a small section of the DLTWTP, which is currently served by a 480 V supply and is approximately 300 kW in size, the hydro generator could be added as a backup power supply similar to the SFP option described above. This option is also not recommended.

3. Parallel Interconnection to the SPF: Whenever the hydro plant is available for generation, add the hydro unit to the metered main electrical feed at the SPF, requiring relay protection and a synchronizer system to ensure the hydro unit interconnects appropriately. This design concept would basically reduce the main power requirement from TECO for the total facility whenever the hydro plant is operating and exports excess power to the TECO grid. A parallel interconnection generating facility for the SPF would likely be a Tier 3 Renewable Generator System (RGS) as defined by TECO subject to their approval and interconnection agreement.

4. Parallel Interconnection to the DLTWTP: Whenever the hydro plant is available for generation, add the hydro unit to the metered main electrical feed at the DLTWTP, requiring relay protection and a synchronizer system to ensure the hydro unit interconnects appropriately. This design concept would basically reduce the main power requirement from TECO for the total facility whenever the hydro plant is operating. A parallel interconnection generating facility for the DLTWTP would likely be a Non-export Parallel Operator (NPO) as defined by TECO subject to their approval and interconnection agreement.

The Florida Renewable Generation Net Metering Incentive Program (see also Section 4.2) establishes rules for qualifying customers supplying excess renewable energy to the grid or supplementing power demand at a metered facility without exporting excess power to the grid. For qualifying parallel generations capable of supplying excess renewable energy to the grid, the rules include the ability to carry forward net excess generation (NEG) at the utility's retail rate to a customer's next bill for up to 12 months. This could help spread out the financial benefits of peak generation periods if applied to a facility with power demands less than the peak generated periods. An excerpt from the Florida Administrative Code is attached (see Appendix D) for further details on the interconnection rules and process. The new HRD generating facility would be classified as a Tier 3 range (100 kW–2 MW) project under the Code.

While outside the scope of this study, the Federal Energy Regulatory Commission (FERC) does have regulatory policy regarding "small generator" interconnections; however, applicability to this project is considered unlikely. Generally, FERC's small generator interconnection standards apply to distributed energy resources up to 20 MW that involve inter-state transmission, and since a TECO interconnection is considered intrastate, jurisdiction would likely fall under the State's public utility commission.

2.6 Preliminary Concepts

The different generator design options will have differing impacts on the dam structure. Two concepts are developed with this study including a siphon-style system over the dam with the generating unit on the upstream side and a downstream generating crossflow system utilizing the existing LFO. Additional concepts were discussed, including a downstream configuration that utilizes the north or south radial gates; however, they were not explored due to the relatively significant structural modifications necessary to support the generating units making them not cost effective.

While the two concepts are presented individually, a third concept is combining both the siphon-style and downstream crossflow systems.

Siphon-Style Design Concept

A typical siphon-style design of a hydro generator would consist of a suction tube on the upstream side of the dam in which the turbine generator package in installed, a horizontal transition tube installed across the top of the dam, and a discharge tube, or draft tube, on the downstream side of the dam. In order to achieve the designed flow and generation using the normal pool elevation of 22.5 feet MSL, it is recommended the siphon tube structure crosses the dam at an elevation lower than the dam crest of 29.0 feet MSL. This can be achieved by installing the siphons through the upper section of the concrete dam with a new structurally reinforced and sealed penetration. This would allow the suction side of the system to function properly and maintain sufficient suction to enable the siphon operation.

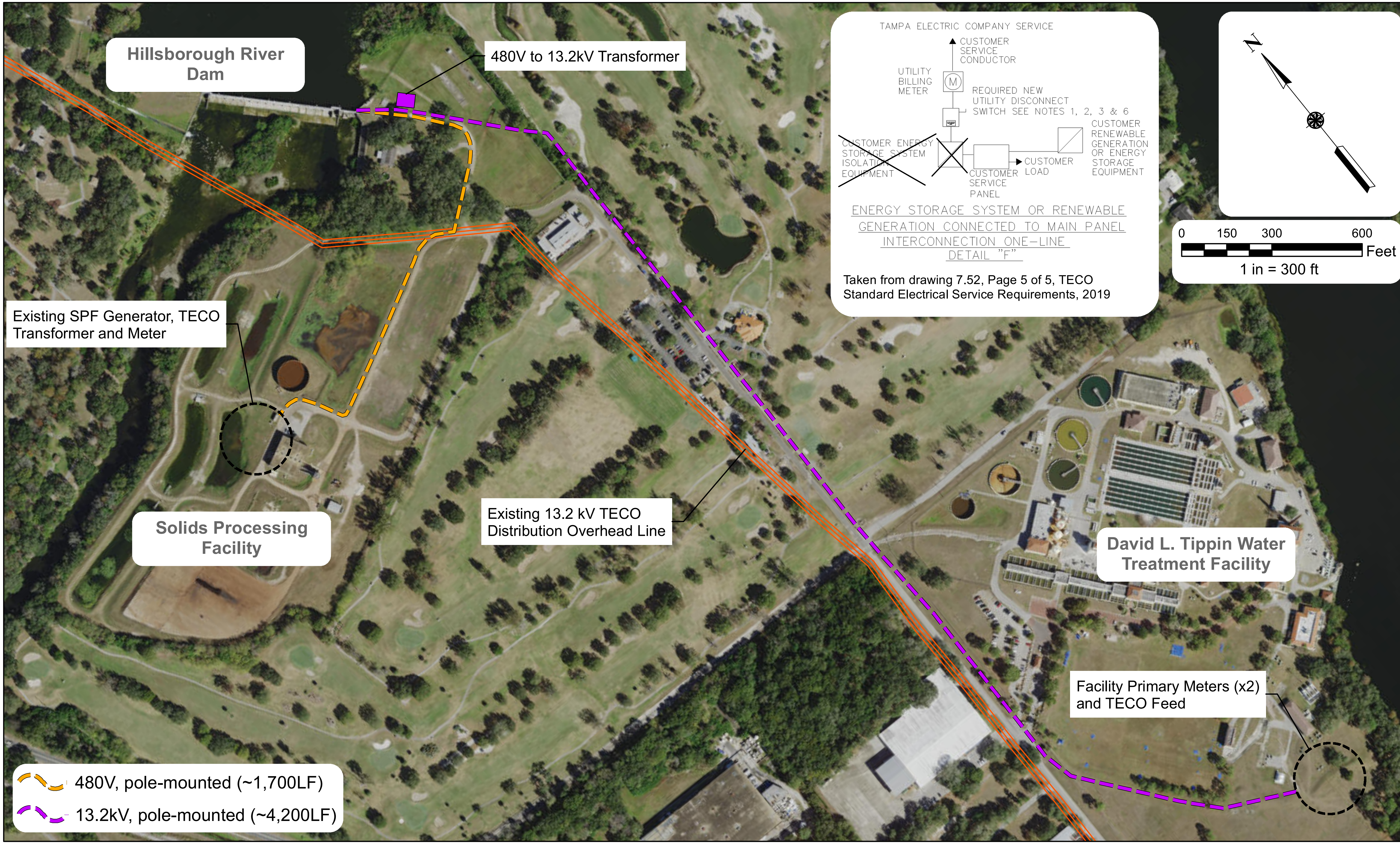
The discharge tube would have an exit point at approximately 2 feet MSL, which would achieve the maximum possible net head, thus maximizing the potential power output from the installation. A siphon machine is started as a motor driving the turbine as a pump. After the siphon tube is filled with water, the unit is switched electrically to perform as a turbine–generator set, and the unit begins to generate power. To shut down the unit, a siphon breaker valve is opened in the discharge/draft tube, which stops the water flow through the turbine.

Figure 5 is a conceptual layout and Figure 6 of a siphon design generation plant using two Mavel TM-10 units mounted on the left end of the HRD. Modifications would be required on the downstream side of the dam such as a discharge structure for energy dissipation and erosion protection of the subgrade.

Because reducing the elevation of the discharge tube across the dam is preferable to improve performance, a penetration or notch through the upper portion of the dam may be necessary.

The generator and turbine units could be removed for maintenance using a portable crane. Power and control/communication cabling for these units would be installed via a conduit system across the top of the dam, in a manner similar to the existing conduit layout. The electrical connection would then proceed away from the dam toward the existing control house, and then to an above-ground pole line to the SPF or DLTWTP, as shown in Figure 4.

If the interconnection is to be made to the DLTWTP, a step-up transformer would be installed as shown in Figure 4, in an area adjacent to the control house.



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Electrical Interconnection Options
Figure 4

LFO Design Concept

If a turbine generator is installed at the LFO, a discharge pool will be needed to provide the required submergence of the turbine outlet. The pool could be supported by a concrete structure that effectively raises the tailwater to an acceptable level to establish adequate submergence of the turbine to operate efficiently. Additionally, sufficient energy dissipation and erosion protection must be incorporated to protect the structure and the streambed immediately downstream of the dam. The discharged water would then flow directly into the river.

Upstream installation of a turbine generator, such as the Voith Stream Diver, will require a structure to be installed against the upstream wall of the dam. This structure will allow the generator unit to be lowered into the upstream pool and mount against the existing slide gate/rectangular inlet to the LFO.

Installation of a Kaplan (bulb) turbine generator unit on the downstream side of the LFO will require a concrete structure to support the unit, with a transition section to connect the existing LFO circular discharge to the inlet of the turbine. As noted above, both these options will require a tailwater pool at the discharge to create adequate submergence for the machine to operate properly and provisions for erosion protection of the streambed.

Installation of an Ossberger-designed crossflow turbine at the downstream side of the LFO could possibly reduce the magnitude of the discharge pool and overall structure to support the unit. Figure 7 is a conceptual layout modifying the LFO with an Ossberger crossflow turbine unit mounted on an LFO conduit extension. Some modifications would be required on the downstream side of the dam in order to install the unit, as well as trash racks on the upstream side.

The generator and turbine unit could be removed for maintenance using a portable crane. Power and control/communication cabling for these units would be installed via a conduit system across the top and downstream face of the dam. The electrical connection would then proceed away from the dam toward the existing control house, and then to an above-ground pole line to the SPF or DLTWTP, as shown in Figure 4.

If the interconnection is to be made to the DLTWTP, a step-up transformer would be installed as shown in Figure 4, in an area adjacent to the control house.

2.7 Cost-Benefit Analysis

Preliminary estimates were developed for the Mavel siphon design generating facility concept using the TM-10 model, which is capable of generating power over the range of flows from 30 cfs up to 170 cfs. A base model TM-10 unit is estimated to cost approximately $250,000 each. These units can be constructed to generate power at 480 V, and thus could be a viable option for the siphon design option. This configuration would minimize additional electrical equipment if the unit(s) were connected directly to the SPF 480 V electrical system.

With the assumed available net head of 15.4 feet and a flow of 170 cfs, the unit could generate 171 kW. This output level would be available for 33% for the year, resulting in a total gross energy generation of 494,000 kWh per year. Adding a second TM-10 unit in parallel to the first unit and taking advantage of the increased flow at the dam for a slightly shorter period of time would allow the 171 -kW output to be doubled for 23% of the year. This would result in an additional 345,000 kWh of plant output per year. Thus, the total generated energy from two machines would be approximately 839,000 kWh per year. This is equivalent to approximately 75% of the annual energy requirement for the SPF. Both machines operating would generate approximately 342 kW, which could meet the demand at the SPF for the months that both units are operating. This could reduce the demand charge for several months each year, as typically the monthly demand charge from the utility is related to the maximum power draw by the customer for the previous month or months.

If the total 2019 electric billing from TECO for the SPF is considered, the equivalent energy charge would be approximately $0.09/kWh. Using this value, the energy generated by this configuration would result in approximately $75,500 per year of avoided cost.

Two Mavel TM-10 units delivered to the site could cost approximately $450,000. Assuming minimal electrical and structural work, the conceptual-level installed cost could be approximately 1,990,000, which would result in a payback period of approximately 20 years at $0.09/kWh, or 26 years at $0.12/kWh.

2.8 Conceptual-Level Construction Cost Estimate

The conceptual-level construction cost estimate for a hydro plant with one Mavel TM-10 generating unit is estimated to be approximately $1,160,000 and the estimate for two Mavel TM-10 generating units is estimated to be approximately $1,990,000. Both estimates are based on a power feed to the SPF. A breakdown of the estimates are provided in Table 4 and Table 5 below.

Both estimates include a 40% contingency and exclude other owner-related costs such as field explorations, design engineering, construction management, quality assurance, legal, administrative, permitting, program/project management, and escalations. The cost estimate generally follows the AACE Guidelines of a Class 5 (Concept Screening) cost estimate based on the concept-level design with a Class 5 estimate expected accuracy low range of -20% to -50%, and an expected accuracy high range of +30% to +100%. See Appendix C.1 for supporting information.

Table 4 – Mavel TM-10 to SPF Concept-Level Cost Estimate

	Description	**Cost Estimate**
1	Equipment	$ 250,000
2	Building structure	$ -
3	Site work	$ 250,000
4	Electrical work	$ 50,000
	Subtotal	**$ 550,000**
5	Mobilization, Bonds, Insurance, and Tax (15%)	$ 82,500
6	Unlisted Items (15%)	$ 82,500
7	Site Cleanup and Demobilization (10%)	$ 55,000
	Subtotal	**$ 770,000**
8	Indirect Costs (10%)	$ 77,000
9	Estimate Contingency (40%)	$ 308,000
	Total Construction Including Estimate Contingency (Rounded) [1]	**$ 1,160,000**

[1]AACE Class 5 estimate expected accuracy low range of $580k - $928k (-20% to -50%); and an expected accuracy high range of $1.5M - $2.3M (+30% to +100%).

Table 5 – Quantity 2 Mavel TM-10 to SPF Concept-Level Cost Estimate

	Description	Cost Estimate
1	Equipment	$ 450,000
2	Building structure	$ -
3	Site work	$ 450,000
4	Electrical work	$ 90,000
	Subtotal	**$ 990,000**
5	Mobilization, Bonds, Insurance, and Tax (12%)	$ 118,800
6	Unlisted Items (12%)	$ 118,800
7	Site Cleanup and Demobilization (10%)	$ 99,000
	Subtotal	**$ 1,326,600**
8	Indirect Costs (10%)	$ 132,660
9	Estimate Contingency (40%)	$ 530,640
	Total Construction Including Estimate Contingency (Rounded) [1]	**$ 1,990,000**

[1]AACE Class 5 estimate expected accuracy low range of $995k - $1.6M (-20% to -50%); and an expected accuracy high range of $2.6M - $4.0M (+30% to +100%).

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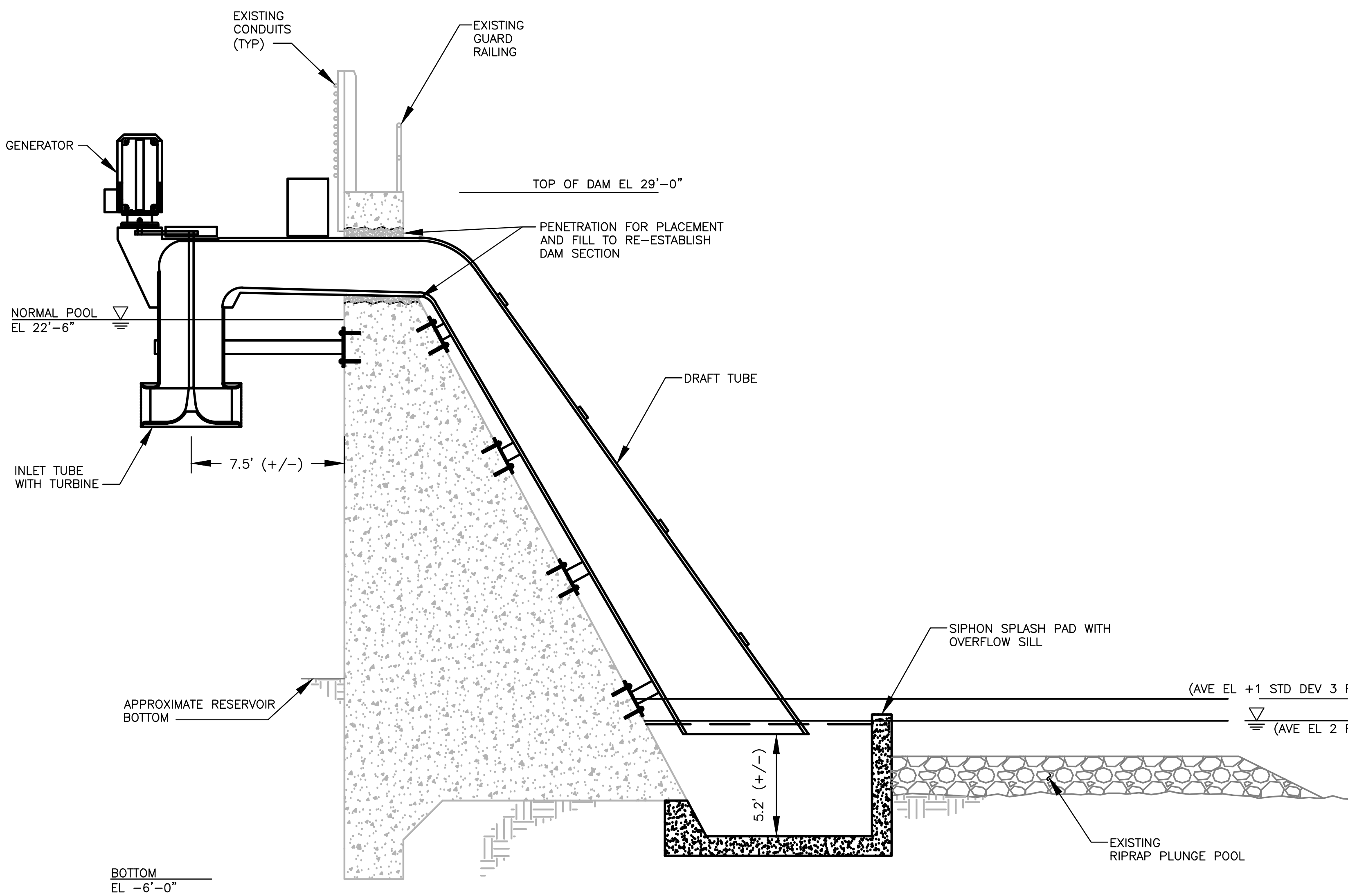

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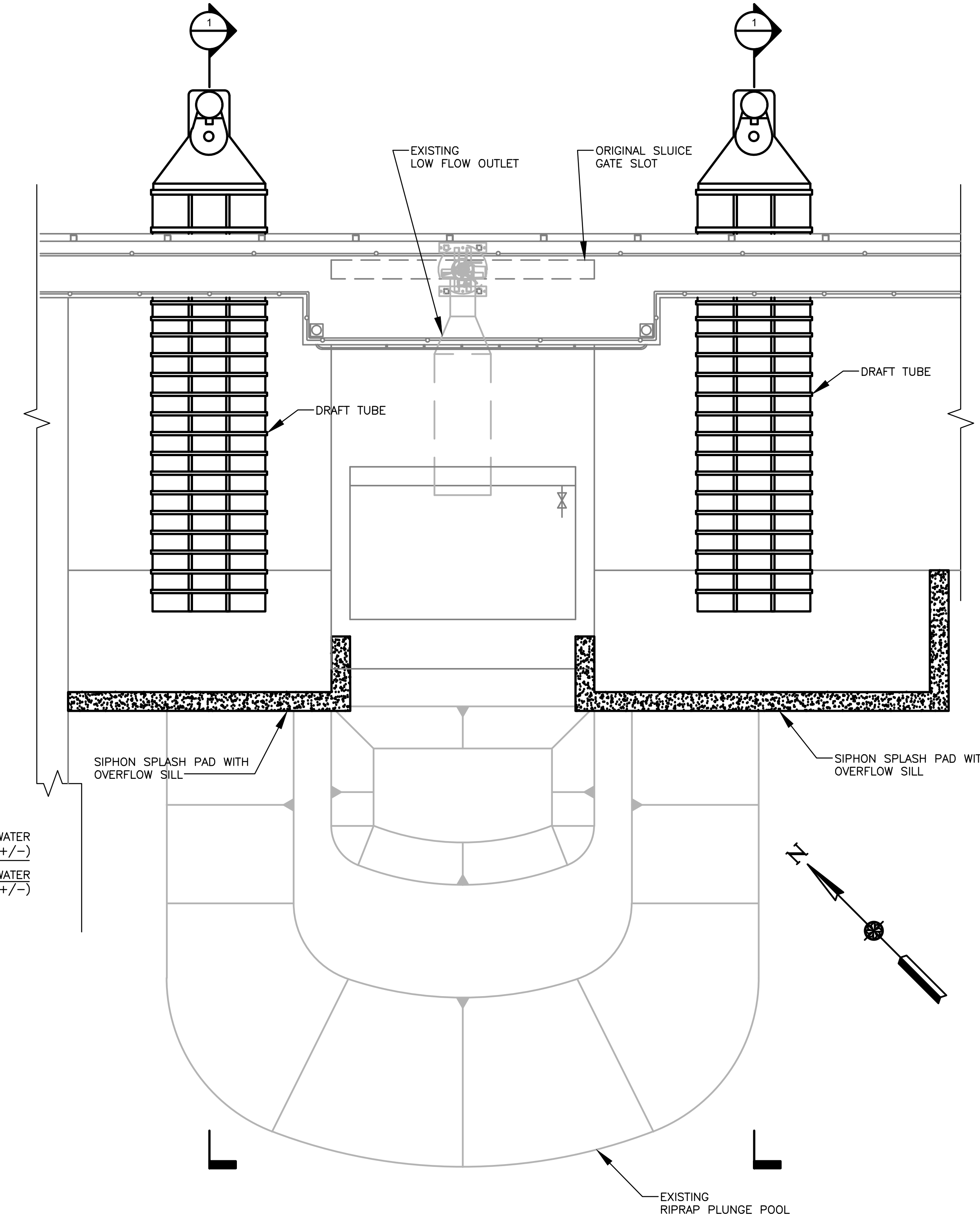

PLAN VIEW
NTS

SHEET NOTES:

1. ELEVATIONS ARE APPROXIMATE BASED ON RECORD DRAWINGS.

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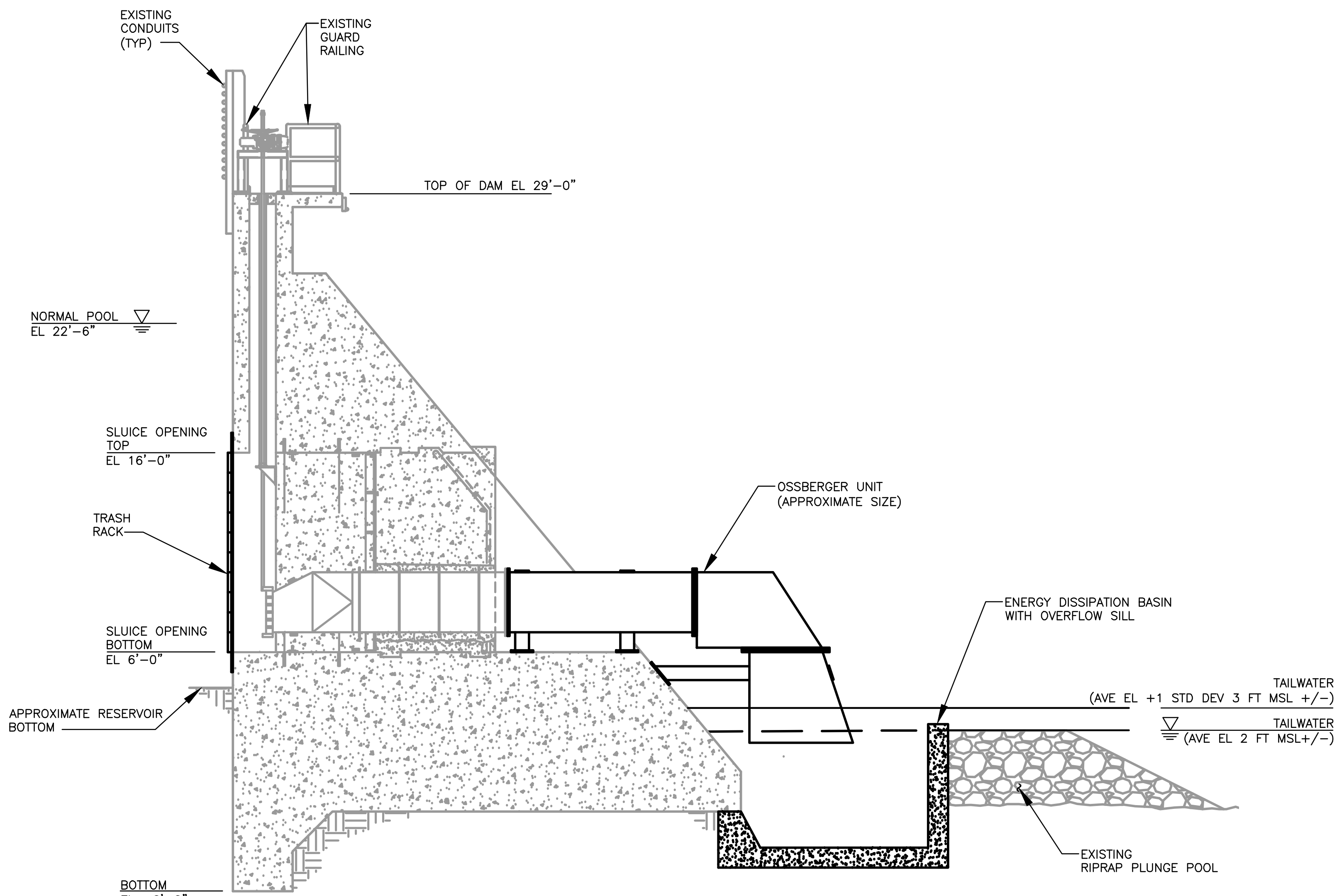
Conceptual Layout of Siphon Design Using Two Mavel TM-10 Units
Figure 5

Gannett Fleming

Rendering of Siphon Design Using Two Mavel TM-10 Units



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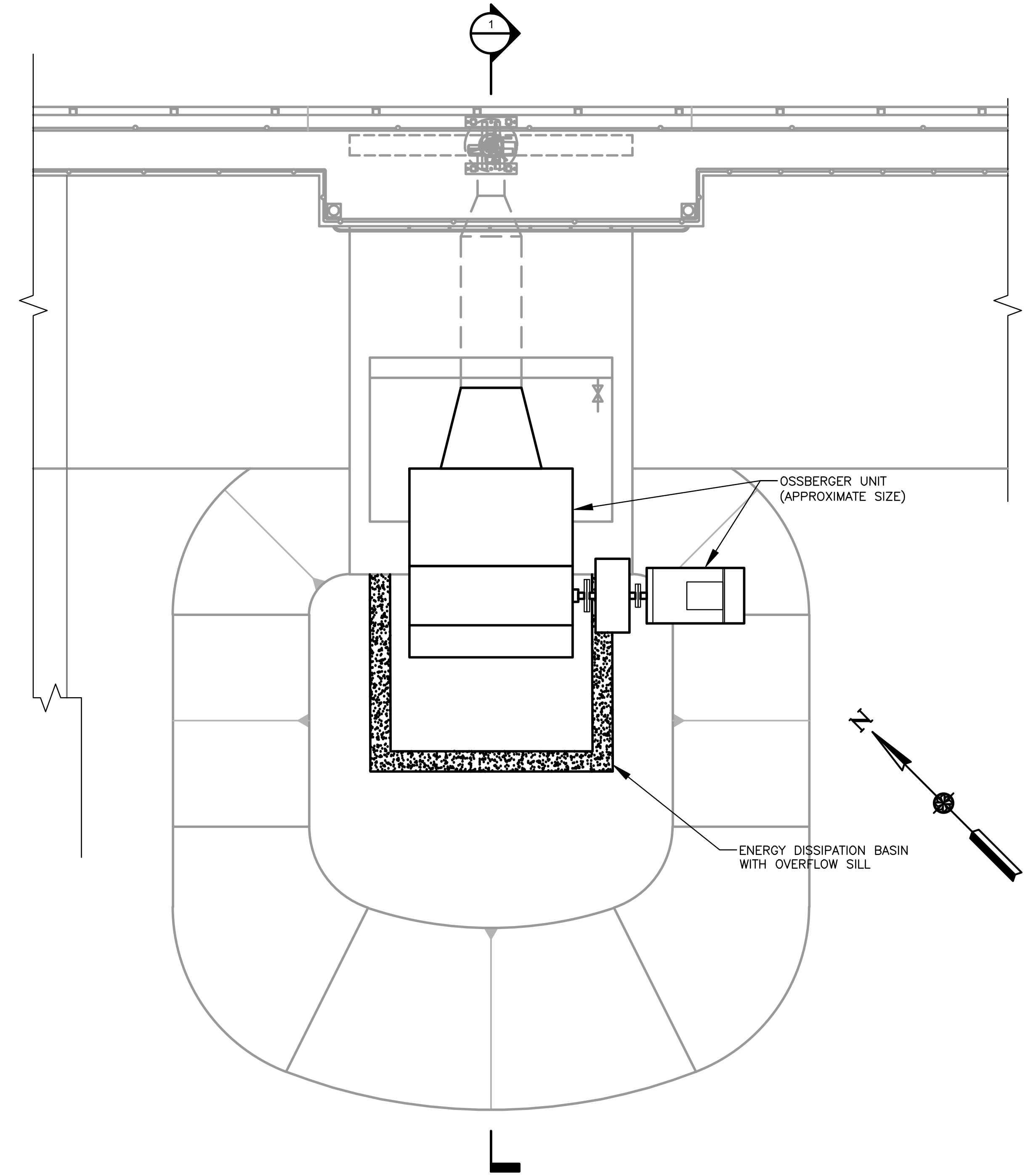

PLAN VIEW
NTS

SHEET NOTES:

1. ELEVATIONS ARE APPROXIMATE BASED ON RECORD DRAWINGS.

Gannett Fleming

Conceptual Layout of LFO Ossberger Crossflow Turbine Unit
Figure 7

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2.9 Sensitivity Assessment

The preliminary analysis of the available head and flow has shown that the maximum generation which could be achieved via the LFO option would be approximately 235,000 kWh per year. A similar analysis of possible generation using a two-unit siphon style design facility yields approximately 870,000 kWh per year.

Given the present design of the dam, two siphon-style units could be installed with no changes to the gates on the dam. Removing one or more gates from service and installing generating units in their place was not evaluated. It is believed that the gate removal and associated construction cost for a generating unit at that location would be excessive, given the generation potential.

A simple payback calculation was performed considering two electric prices – the current average energy cost for the SPF ($0.09/kWh) and a rate 33% higher ($0.12/kWh). Note the following payback calculations are based on the conceptual level construction cost estimate and do not address inflation rates, operation and maintenance (O&M) costs or other similar potential impacts on the evaluation. Annual operation and maintenance costs can be estimated during the next phase of the project and included in the payback calculation.

A budgetary cost estimate from Mavel (see Appendix C.1) for the siphon-style TM-10 unit as well as an estimate for two identical units which could be installed at the HRD were used when developing the estimated capital costs.

Table 6 – Simple Payback Calculation for Single TM-10 Unit

	Unit 1
Generation Estimate (kW)	171
Operation Per Year (hours)	2,891
Total Annual Generation (kWh)	494,327
Billing offset from generation @ $0.12/kWh	$59,319
Billing offset from generation @ $0.09/kWh	$44,489
Capital Installed Cost	$1,160,000
Payback Period (years @ $0.12/kWh)	20
Payback Period (years @ $0.09/kWh)	26

Table 7 – Simple Payback Calculation for Two TM-10 Units

	Unit 1	Unit 2
Generation Estimate (kW)	171	171
Total Generation Estimate (kW)	342	
Operation Per Year (hours)	2,891	2,190
Annual Generation (kWh)	494,327	344,531
Total Annual Generation (kWh)	838,858	
Billing offset from generation @ $0.12/kWh	$59,319	$41,344
Billing offset from generation @ $0.09/kWh	$44,489	$31,008
Capital Installed Cost	$1,990,000	
Payback Period (years @ $0.12/kWh)	20	
Payback Period (years @ $0.09/kWh)	26	

2.10 Conclusions

Through an initial screening-level process, the modular siphon-style hydroelectric units were evaluated for this proof-of-concept study due to their relatively low impact to the existing non-overflow section of the dam and therefore lower design and capital costs. Annual power generation for a single Mavel TM-10 siphon-style unit is estimated at approximately 494,000 kWh and annual power generation for two Mavel TM-10 units is estimated at approximately 839,000 kWh. Both configurations have an estimated payback period of approximately 20–26 years depending on the cost of electricity. The relatively long payback period is primarily due to the seasonally variable flow rates and the low net head.

The application of a downstream crossflow unit taking advantage of the existing LFO within the non-overflow section of the dam was also evaluated for similar reasons to the modular siphon-style units. While a separate cost estimate and payback period was outside the scope of this study, the periods of power generation for a unit utilizing the LFO would be longer based on the flow duration curve; however, their power output would be less due to the limited discharge capacity of the LFO and low net head.

A third configuration of combining the higher-capacity Mavel TM-10 units with the lower-capacity crossflow unit would further increase power generating capacity by providing generating options through a larger range of the flow-duration curve.

Generator options considered in this study typically operate at an output voltage of 480 V. Thus, it would be reasonable to expect that a connection to the SPF would require no additional transformer, as the generating voltage could be the same as that used in the SPF. In addition, since the SPF is relatively close to the proposed location for the new hydro unit, the power could be supplied to the SPF via a 1,700-foot long 480 V power line. A connection to the DLTWTP would require the addition of a transformer to step the generated voltage of 480 V up to 13.2 kV. The transformer output would be connected to the DLTWTP via a 4,200-foot long dedicated 13.2 kV transmission line and terminate at the DLTWTP electrical connection.

Of the grid/plant interconnection options review, a parallel net metering electrical interconnection is recommended at the SPF or DLTWTP TECO electrical feed. If added to the SPF, the project may qualify as a Tier 3 system (100 kW-2 MW) through the Florida Renewable Generation Net Metering Incentive Program including the ability to carry forward net excess generation (NEG) at the utility's retail rate to future bills for up to 12 months. If the project qualifies, generated energy would be consumed by the facility first and NEG would be supplied to the TECO grid under the interconnection agreement. Considering the benefits of this program, a TECO net metering interconnection appears to be the most favorable option particularly when applied at the SPF which operates at the same voltage (480 V), is closer than the DLTWTP, and has power demands which more closely match the power generation capabilities.

While potential environmental impacts are outside the scope of this proof-of-concept study, it is acknowledged they must be considered during future phases of feasibility and design. Additionally, social benefits should also be considered such as educational opportunities to the public and community.

Recommended items for the next phase may include: 1) begin conversations with TECO and evaluate their detailed requirements for interconnection under Florida's Renewable Generation Net Metering Incentive Program; 2) prepare a basis-of-design, 15% design, and updated cost estimate; 3) perform a desktop permitting assessment; and 4) evaluate project delivery options (e.g. Design Bid Build, Design Build, Construction Manager at Risk, Engineer Procure Construct, etc.).

3.0 Re-Pumping System Inline Energy Recovery Evaluation

The Interbay Re-Pumping System (RPS) comprises a ground storage tank and a re-pumping station located at 3710 W. Wisconsin Avenue. The ground storage tank has a diameter of 163 feet, a height of 32 feet, and a capacity of 5 million gallons. The re-pumping station is housed in a separate building adjacent to the storage tank and consists of four booster pumps and two jockey pumps. The tank is fed by a 24-inch water main and flow is controlled by an altitude valve. The altitude pilot valve controls tank operations and the water level in the tank by sensing the hydrostatic head. Pressure readings are reported in the facility's SCADA system. The City of Tampa is undergoing an improvement project at the Interbay RPS including replacing the existing valve with a sleeve valve and other control improvements. This section evaluates conceptual alternatives for installing an energy recovery system at the Interbay RPS facility for harvesting available head in the system, taking into consideration site space restrictions, operations, associated equipment, and the planning level capital cost.

3.1 Existing Operational Diurnal Patterns

The evaluation of operational parameters is for better understanding of operational requirements and possible limitation boundaries for energy recovery units. The energy recovery system would be set up to harvest available pressure upstream of the altitude valve. For this evaluation, historical SCADA data for 2019 was requested and provided to Gannett Fleming for review. The data set included tank discharge flow, tank levels, and inlet pressure in 15-minute intervals. The Interbay facility does not measure the tank's incoming flow, so this value was calculated based on the discharge flow plus the change in volume for each time interval. Diurnal curves were developed for the incoming flow, pressure, and tank level. The diurnal curves were developed after anomalies such as negative flow values, negative tank levels, tank levels exceeding the actual tank capacity, or constant data for extended periods of time were removed from the data. Average daily curves were produced for each month and were reviewed for potential patterns relating to wet or dry seasons. Because no patterns were identified, all months were averaged together to produce a single diurnal curve at 15-minute intervals. From the SCADA data it is evident that the tank has a 24-hour operation, with most of the tank filling occurring in the early hours of the morning. Table 8 summarizes the range and averages of each of the three diurnal curves.

Table 8 – Interbay Incoming Flow, Pressure and Tank Levels

	Average	Maximum	Minimum
Incoming Flow (mgd)	6.69	10.06	4.62
Pressure (psi)	49.40	56.10	36.99
Tank Level (ft)	21.94	22.57	20.73

Diurnal curves were plotted to compare incoming flow versus pressure as shown in Figure 8, pressure versus tank level as shown in Figure 9, and flow versus tank level as shown in Figure 10.

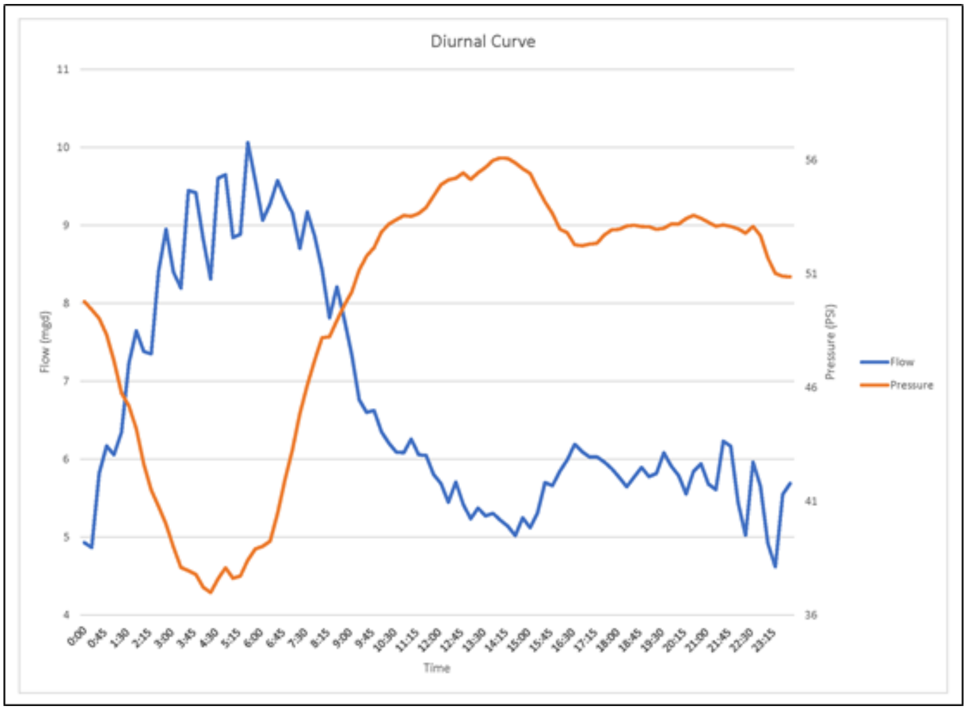

Figure 8 – Interbay Diurnal Curves (Flow vs. Pressure)

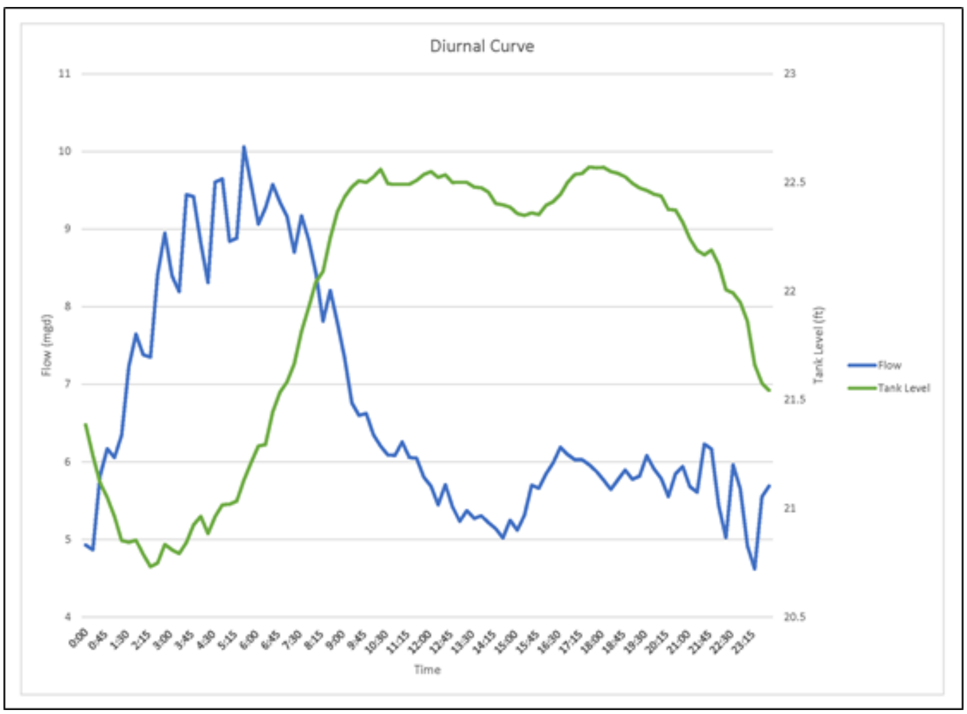

Figure 9 – Interbay Diurnal Curves (Flow vs. Tank Level)

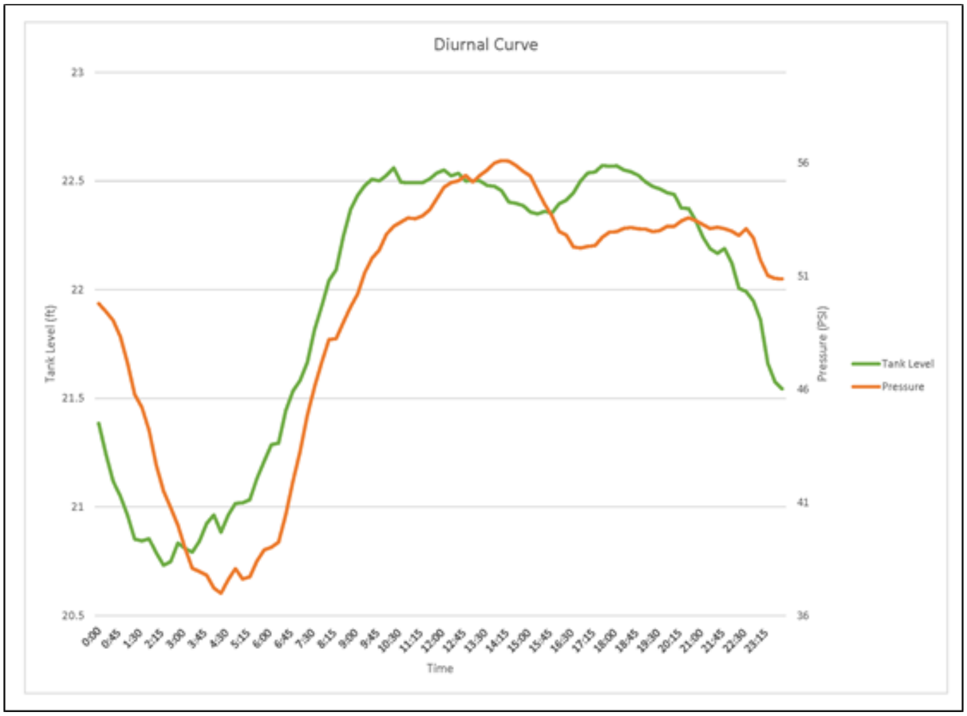

Figure 10 – Interbay Diurnal Curves (Tank Level vs. Pressure)

3.2 Preliminary Location Assessment

For this evaluation, the site arrangement and footprint are based on the ongoing tank improvement projects. Based on the site visit and drawings, the Interbay RPS location provides for adequate spacing for retrofitting and installing an energy recovery unit. Confirmation of underground conflicts will be required at the detail design phase. Based on available technologies, energy recovery units should be installed either in a vault or in a building structure, protected from the elements.

For the purpose of this conceptual evaluation and given the arrangement of the yard piping for the fill line, two arrangements were identified. Location 1 is directly south of the existing altitude control valve, is not shown to have underground utilities, provides for maintenance access, and allows for above or below ground structures to house the energy recovery unit. This location allows for adequate space for a building structure, with an estimated footprint of 22 feet by 20 feet, which will house the proposed unit. This location provides for ease of operation and maintenance clearances, and storage area for items such as spare parts or maintenance equipment. Location 1 does impact the existing landscape surrounding the tank inlet, but impacted plants may be relocated outside the perimeter of the proposed building structure.

Location 2 is directly north of the tank inlet and contains the underground 24-inch bypass that directs flow to the adjacent RPS. Additionally, the area contains the existing electrical conduits that connect the flow control system to the electrical room. Therefore, this area is slightly more restricted and congested than Location 1. Location 2 has sufficient spacing for a building structure; however, it is estimated that a maximum building with a footprint of 21 feet by 12 feet could house the proposed equipment at Location 2 and would not allow for additional storage area.

Both locations are in close proximity to the facility's electrical room; however, Location 2 may require the partial relocation of the existing underground electrical conduits. Preliminary system layout sketches are provided in Figure 11 and Figure 12 for both location alternatives.

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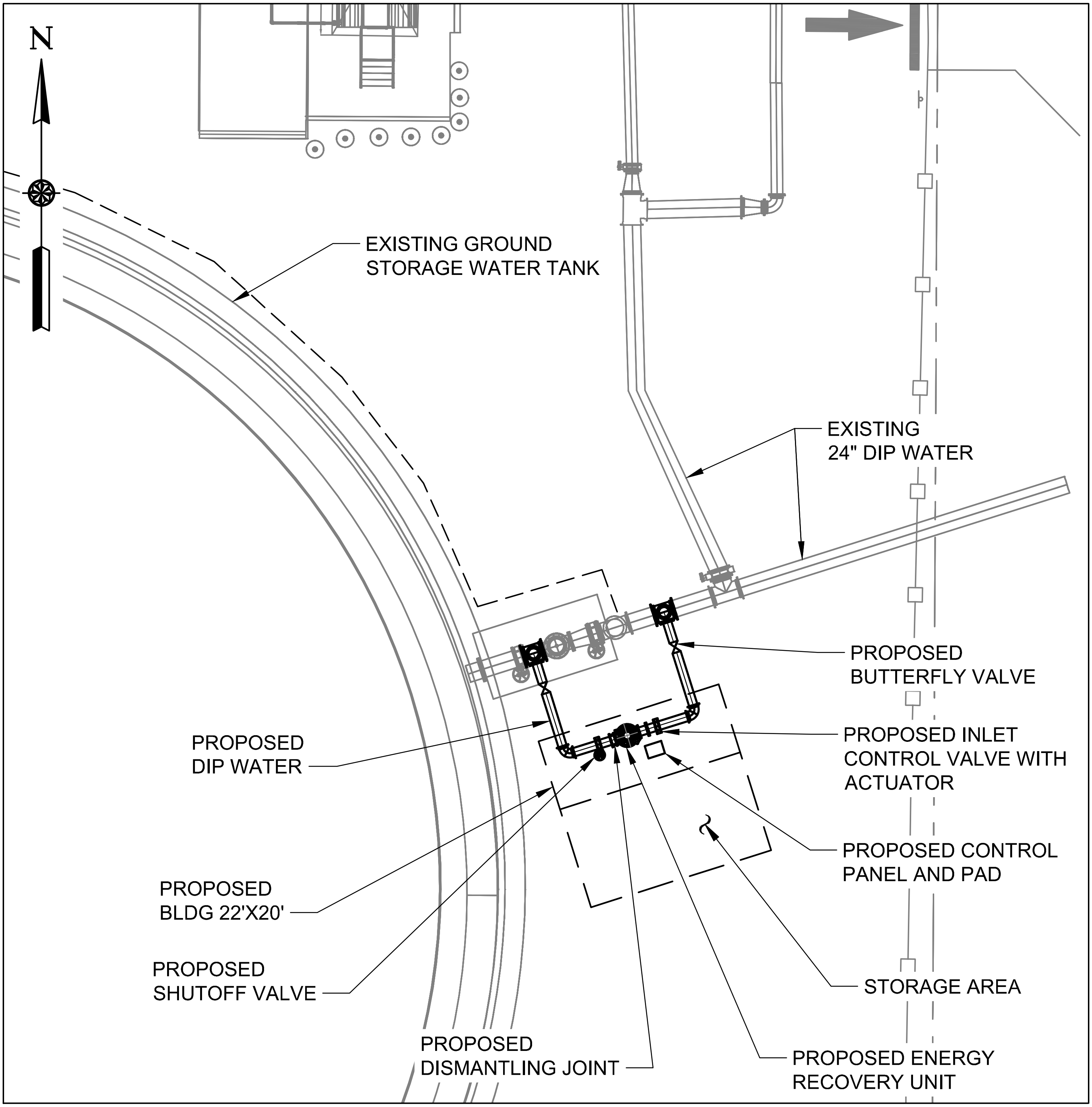

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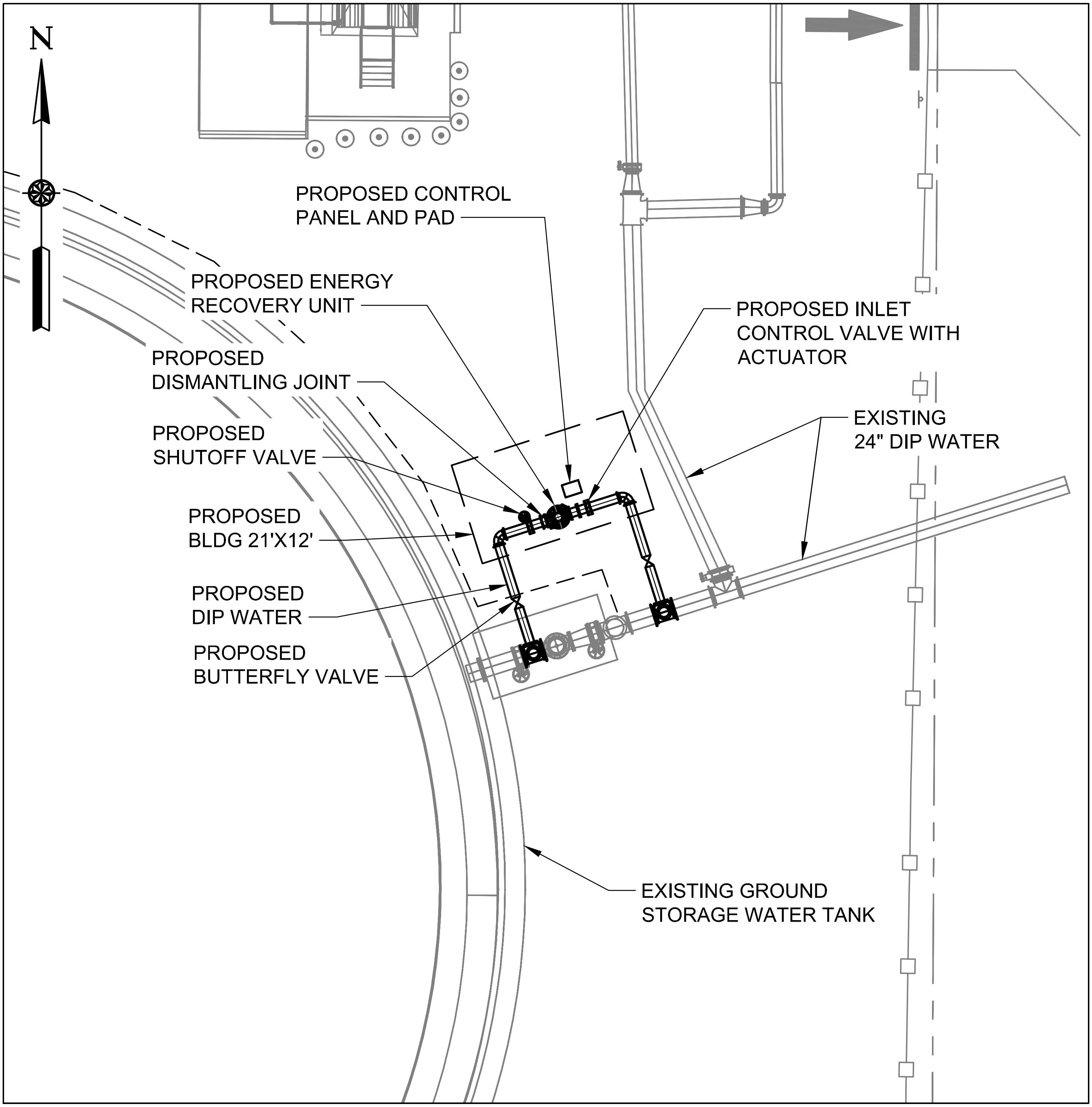
Gannett Fleming

Location and Layout of Proposed
Energy Recovery Unit (Location 1)
Figure [redacted]



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Gannett Fleming

Location and Layout of Proposed
Energy Recovery Unit (Location 2)

Figure 1[redacted]

3.3 Energy Recovery Technology Options

Available technologies for energy recovery units were reviewed for their applicability to potable water distribution systems and compatibility with operational boundary conditions of the Interbay system. Based on internal discussions and the data sheets for energy recovery technology, several technologies were identified for possible application and initial screening. Table 9 summarizes the manufacturers and energy recovery units that were considered, along with a corresponding high-level description and applicability. Units vary from turbines, both reaction and impulse, to pumps as turbines (PATs).

After consideration of site-specific arrangement for the Interbay Facility and anticipated footprint and associated equipment it was determined that a similar area would be required for the turbine and PAT applications. Francis turbines are reactive turbines and are produced by several manufacturers. In a Francis turbine, water flows through a spiral casing and the blades rotate as the flow hits in a perpendicular direction. Required design arrangement and associated equipment include a bypass tie-in from the existing flow control valve, followed by an inlet control valve with an actuator prior to the turbine. The turbine generator will be followed by a shutoff valve, with piping continuing to a connection to the main incoming flow line just downstream of the existing flow control valve. This arrangement is required to be installed either in a vault or in a building structure that will protect the equipment, including an electrical control panel, from the elements. The enclosure will also contain noise created by the equipment.

The PAT uses a centrifugal pump operating in reverse mode, acting in a similar manner as the Francis turbine. The PAT installation follows a similar arrangement as the one described above for the Francis turbine, and also requires shelter within a vault or a building structure. Figure 13, below, shows examples of a Francis turbine and a PAT installation.

Figure 13 – Francis Turbine (Canyon Hydro, left) and PAT (Rentricity, right).

Table 9 summarizes the manufacturers and units that were considered, along with the corresponding evaluations. A list of potential manufacturers which were evaluated and supporting marketing materials are included in Appendix B.

Table 9 – Evaluated Manufacturers for Energy Recovery Options

Manufacturer / Unit	Type of Equipment	Pressure, Flow, Power Generating Capacity	Applicable to Interbay Facility	Notes
Voith PipeRunner	In-line turbine with a horizontal propeller.	Pressure limit of 28.4 psi; flow range up to 91.3 mgd; and an output power capacity of up to 250 kW.	No	This technology is not compatible with the Interbay facility due to the limitation on pressure of up to 28.4 psi, which is significantly lower than the operational pressures recorded at the facility.
LucidEnergy™ Power System	Spherical turbines installed within 24-inch to 60-inch water transmission lines.	This application has an output power capacity of 18 kW.	No	This application does not fit the Interbay facility due to the minimum flow requirement of 24 mgd that are not available at the Interbay facility.
Tesimag M.A.S.	In-line hydraulic micro turbines	Power generating capacity ranges from 1 kW to 400 kW of power output capacity.	Yes (with limitations)	Three different sizes of multistage turbines are available from this manufacturer, with MAS-10 being applicable to the Interbay facility. MAS-10 is limited to a pressure range of 7.1–142.2 psi; flow range of 7.6–15.2 mgd; and a power output capacity of 10–400 kW. This unit could potentially be considered for the Interbay facility; however, operation of the unit would be limited to periods of time when the higher flows are present. This unit is manufactured and used in Europe; thus, information was not readily available as it relates to the NSF compliance for drinking water systems in the United States.
HydroCoil 600	Screw-type turbine for use within 6-inch to 12-inch diameter water lines	Pressure range of 5.7–28.4 psi and a power output capacity of up to 8 kW.	No	This type of technology is not applicable to the Interbay facility due to the low power generating capacity.
Canyon Hydro SOAR ILT12	Francis turbine and generation unit	Expected power output capacity between 42–72 kW.	Yes	It is noted that the unit would be limited to 8.7 mgd at an available pressure of 37 psi; thus, the existing flow control system would be used in parallel.
Rentricity – Cornell Pump	Pump as turbine and generation unit	Expected power output capacity between 50-75 kW.	Yes	This technology is applicable to the Interbay facility.
Other PATs	Pumps as Turbines, centrifugal pumps operating as turbines, are built by different manufacturers, such as SPP Pumps or Cornell Pumps.			

Three vendor provided energy recovery systems were considered:

- Canyon Hydro – SOAR ILT-12-60-9.0:
  The equipment includes Francis turbine with hydraulic actuation, induction generator, valves and actuator, hydraulic power unit, controls and switchgear. The cost for the proposed equipment is estimated at $342,000, exclusive of building structure and connection to existing electrical system.

- Rentricity – Cornell Pump 10-TR1 with NSF 61/372 Certification (provided by Rentricity):
  The equipment includes PAT, inlet control valve with pneumatic actuator, main electrical control panel. The cost for the proposed equipment is estimated at $165,000, exclusive of building structure and connection to existing electrical system.

- VOITH:
  The proposed equipment from VOITH consists on a conventional horizontal Francis turbine, this type of unit discharges into a static pool, thus additional infrastructure would be required to accommodate for this arrangement, or modifications to the proposed unit will be required with the manufacturer. The proposed equipment is inclusive of basic standard controls. The cost for the proposed equipment is estimated at $350,000, exclusive of building structure and connection to existing electrical system.

3.4 Conceptual Operation Considerations

The energy recovery unit would have an anticipated production rate between 50 kW and 75 kW, based on an average maximum flow of 10.06 mgd corresponding to a pressure of 38.4 psi, and an average minimum flow of 4.62 mgd corresponding to a pressure of 51 psi. The Interbay ground storage tank has a 24-hour operation, as such the energy recovery unit would have the capability to operate continuously. Control setting for the energy recovery unit would have to maintain sufficient pressure downstream of the unit to maintain filling operations of the ground storage tank; therefore, it would operate as a pressure reducing valve. A schematic process flow diagram is shown in Figure 14 below.

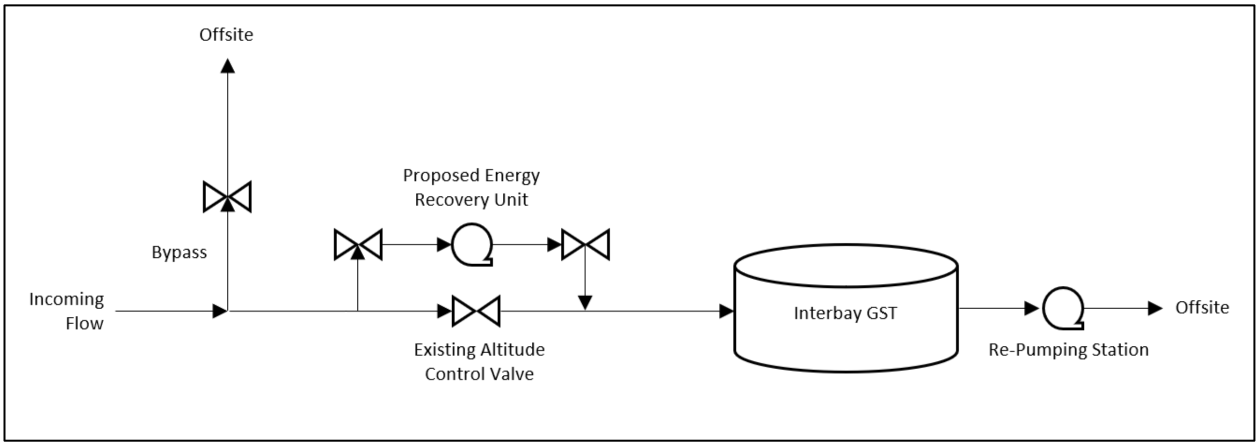

Figure 14 – Schematic Process Flow Diagram

The Interbay facility has an existing electrical room, approximately 100 feet away from the location of the energy recovery unit, with a backup generator, and an above-ground fuel storage tank. The generating voltage for the energy recovery unit would be the same as that used at the Interbay facility, 480 V. to interface power output from the new generating unit to a bus on or adjacent to the existing Main Distribution Panel within the electrical room, an automatic synchronizing switch will be required. Further evaluation on the connection of this unit to the facility's existing electrical system is recommended during a subsequent project phase.

Another possible option for the electrical interconnection would be to add the energy recovery unit as a new generating source on the TECO electrical grid. Energy would be supplied to the TECO grid whenever the energy recovery unit operates, and the generated power would be subtracted from the monthly billing under an interconnection agreement and net-metering program with TECO. The interconnection would be applied to a metered facility, such as the Interbay facility.

The Florida Renewable Generation Net Metering Incentive Program (see also Section 4.2) establishes rules for qualifying customers supplying renewable energy to the grid including the ability to carry forward net excess generation (NEG) at the utility's retail rate to a customer's next bill for up to 12 months. This could help spread out the financial benefits of peak generation periods if applied to a facility with power demands less than the peak generated periods. An excerpt from the Florida Administrative Code is attached for further details on the interconnection rules and process. The new RPS energy recovery unit would be classified as a Tier 2 range (10 kW–100 kW) project under the Code.

Energy recovery units have an inspection and maintenance schedule to be considered. Yearly maintenance includes changing the motor bearing oil and hydraulic oil in the wicket gate hydraulic power unit, and flush seal cooling and drain piping. The typical functional life cycle of these units is approximately 30 years.

3.5 Conceptual-Level Capital Cost Estimate

The conceptual-level construction cost estimate for the Interbay RPS site with one Rentricity unit is expected to be approximately $550,000 which includes a 40% contingency and excludes other owner related costs such as field explorations, design engineering, construction management, quality assurance, legal, administrative, permitting, program/project management, and escalations. The cost estimate generally follows the AACE Guidelines of a Class 5 (Concept Screening) cost estimate based on the concept-level design with a Class 5 estimate expected accuracy low range of -20% to -50%; and an expected accuracy high range of +30% to +100%. See Appendix C.2 for supporting information.

A simple payback period was calculated for the proposed improvements based on continuous operation at the lower power output range of 50 kW to account for times of no operation (see Table 10). It is estimated that with an average cost of $0.09–$0.12/kWh for the Interbay facility, and a power generating capacity of 438,000 kWh per year, the payback period is approximately 10–14 years due to the savings in energy consumption from TECO. It is noted that this estimate excludes O&M costs and is limited to the estimated capital cost estimate listed above. O&M is anticipated to be included as part of the regular preventative schedule for other assets in the Interbay facility. Cost breakdown associated to labor and parts for this proposed energy recovery system would require understanding of current O&M cost for the facility and its allocation to other assets.

Table 10 – Simple Payback Calculation for One Rentricity Unit at the Interbay Facility

	Unit 1
Generation Estimate (kW)	50
Operation Per Year (hours)	8,760
Total Annual Generation (kWh)	438,000
Billing offset from generation @ \$0.12/kWh	\$52,560
Billing offset from generation @ \$0.09/kWh	\$39,420
Capital Installed Cost	\$550,000
Payback Period (years @ \$0.12/kWh)	10
Payback Period (years @ \$0.09/kWh)	14

3.6 Conclusions

The Re-Pumping System inline energy recovery unit is feasible at the site with an estimated payback period of approximately 10–14 years. It is estimated that the unit will have the capacity to generate approximately 50kW–75kW year-round while the RPS is operational.

Given the Florida Renewable Generation Net Metering Incentive Program, and considering potential economies of scale, it may be favorable to consider this type of application at multiple re-pumping stations within the system during future phases of feasibility study and design. While potential environmental impacts are outside the scope of this proof-of-concept study, they are likely minimal due to the low impact footprint of the energy recovery unit. Additionally, social benefits should also be considered such as educational opportunities to the public and community.

Recommended items for the next phase may include: 1) begin conversations with TECO and evaluate their detailed requirements for interconnection under Florida's Renewable Generation Net Metering Incentive Program; 2) evaluate other re-pumping station sites, prepare a basis-of-design, 15% design, and updated cost estimate; 3) perform a desktop permitting assessment; and 4) evaluate project delivery options (e.g. Design Bid Build, Design Build, etc.).

4.0 Desktop Funding Assistance Availability Review

The following is a list of potential funding assistant and incentive programs that generally aligned with elements of the HRD and/or RPS hydroelectric projects. Due to the complex and nuanced language of the programs, more extensive reviews are recommended as the HRD hydroelectric and RPS Energy Recovery projects are further defined in future phases. Additionally, we recommend availability of funding and incentive programs are periodically checked for additions, updates, renewals, expirations and/or repeals.

4.1 Tax Credit Programs

- Business Energy Investment Tax Credit (ITC)
    - Federal program administered by the U.S. Internal Revenue Service.
    - Target recipients are commercial, industrial, investor-owned utilities, cooperative utilities, and agricultural entities.
    - Includes a microturbine credit up to 2 MW in capacity.
    - As a governmental entity (i.e. municipality), the City of Tampa likely does not qualify for this program.
    - Resource: https://uscode.house.gov/view.xhtml?req=(title:26%20section:48%20edition:prelim)

- Renewable Electricity Production Tax Credit (PTC)
    - Federal program administered by the U.S. Internal Revenue Service.
    - Program expired for qualifying hydroelectric facilities commencing construction after December 31, 2017.

4.2 Renewable Energy Incentive Programs

- Florida Renewable Generation Net Metering Incentive Program
    - Florida Public Service Commission (PSC) rules for Interconnection and Net Metering of Customer-Owned Renewable Generation is presented in the Florida Administrative Code under Rule 25-6.065 (7)
    - The rules are inclusive of hydroelectric power.
    - While not a funding program, the rules were developed to promote and expedite qualifying renewable energy interconnection systems within the State.
    - The HRD Hydroelectric application with direct feed into the TECO grid would likely qualify as a Tier 3 system with power generation greater than 100 kW and less than or equal to 2 MW.
    - The RPS Energy Recovery application with direct feed into the TECO grid would likely qualify as a Tier 2 system with power generation greater than 10 kW and less than or equal to 100 kW.

- Energy Policy Act of 2005, Pub. L. No. 109-58 (Section 242), Hydropower Production Incentive Program.
    - The initial program expired in 2015.
    - Additional appropriations were granted in 2018; however, they were to support hydrokinetic technology and therefore are not applicable to this study.
    - Resource: https://www.energy.gov/eere/water/downloads/federal-register-notice-epact-2005-section-242-hydroelectric-incentive-0

  - A new round of funding was recently made available for hydropower generated during the 2019 calendar year.
  - Resource: https://www.energy.gov/eere/water/articles/new-round-hydroelectric-incentive-funding-now-available-0

4.3 Renewable Energy Loan Programs

- U.S. Department of Energy – Loan Guarantee Program
  - Federal program administered by the U.S. Department of Energy.
  - The DOE Loan Guarantee Program was created with Section 1703 of Title XVII of the Energy Policy Act of 2005 and reauthorized by the American Recovery and Reinvestment Act (ARRA) of 2009 by adding Section 1705. The 1705 program was retired in 2011; however, the DOE still has authority to issue loan guarantees under the old Section 1703 Program.
  - While it appears the 1703 program is still being administered, a 2017 amendment restricts eligible projects to involve "new" or "significantly improved technologies", possibly disqualifying manufactured hydroelectric generation units evaluated within this desktop study for the HRD and RPS sites.
  - Resource: https://www.energy.gov/lpo/title-xvii/title-xvii-project-eligibility

- Qualified Energy Conservation Bonds (QECBs) under the Energy Improvement and Extension Act of 2008
  - Federal program administered by the U.S. Internal Revenue Service.
  - Repealed under the Tax Cuts and Jobs Act (HR 1) of 2017, therefore no longer available.

- Clean Renewable Energy Bonds (CREBs) under the Energy Improvement and Extension Act of 2008 with further funding under the American Recovery and Reinvestment Act of 2009.
  - Federal program administered by the U.S. Internal Revenue Service.
  - Repealed under the Tax Cuts and Jobs Act (HR 1) of 2017, therefore no longer available.

- Florida State Revolving Funds (SRF)
  - The Florida SRF consists of a Clean Water State Revolving Fund, and a Drinking Water State Revolving Fund. The program receives Federal appropriations and is administered by the State with EPA oversight.
  - While the HRD hydroelectric facility is not considered eligible for the SRF, the RPS energy recovery project should be evaluated during a future phase for eligibility under the CWSRF Energy Efficiency project type.
  - EPA Resource: https://www.epa.gov/cwsrf/learn-about-clean-water-state-revolving-fund-cwsrf#eligibilities
  - Florida DEP Resource: https://floridadep.gov/wra/srf/content/state-revolving-fund-resources-and-documents

- U.S. Department of Energy Water Power Technologies Office (WPTO) displays Water Power Funding Opportunities. As of May 2020, they listed four opportunities, one of which is hydropower related in the form of prize money for innovative fish exclusion technology projects.

The three-stage competition launched in January 2020 and is underway. We recommend WPTO opportunities are periodically checked for new programs.

- Resource: https://www.energy.gov/eere/water/water-power-funding-opportunities

5.0 References

1. **Stone & Webster.** *Report on the Hillsborough Hydroelectric Power Plant of the Tampa Electric Company, Tampa Florida.* Division of Construction and Engineering. 1920.

2. **Nicholas S. Hill, Jr. Consulting Engineer.** *Report Upon Water Situation Created by Failure of Tampa Electric Company Dam on the Hillsborough River.* 1934.

3. *The Many Lives of the Hillsborough River Dam, Tampa FL.* **Rañon, John A., Vaghti, Stewart S and Burke, Tom.** s.l. : U.S. Society on Dams, 2018.

4. **USGS.** National Water Information System: Web Interface. [Online] [Cited: 03 19, 2020.] https://waterdata.usgs.gov/nwis/inventory/?site_no=02304500&agency_cd=USGS.

5. **Chow, Ven Te.** *Handbook of Applied Hydrology.* New York : McGraw-Hill, Inc., 1964.

6. **Florida Administrative Code.** 40D-8.041 Minimum Flows.

7. —. *25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.*

APPENDIX A – Information on Hydropower Manufacturers