The Small Hydropower Handbook

Colorado Energy Office

Notice

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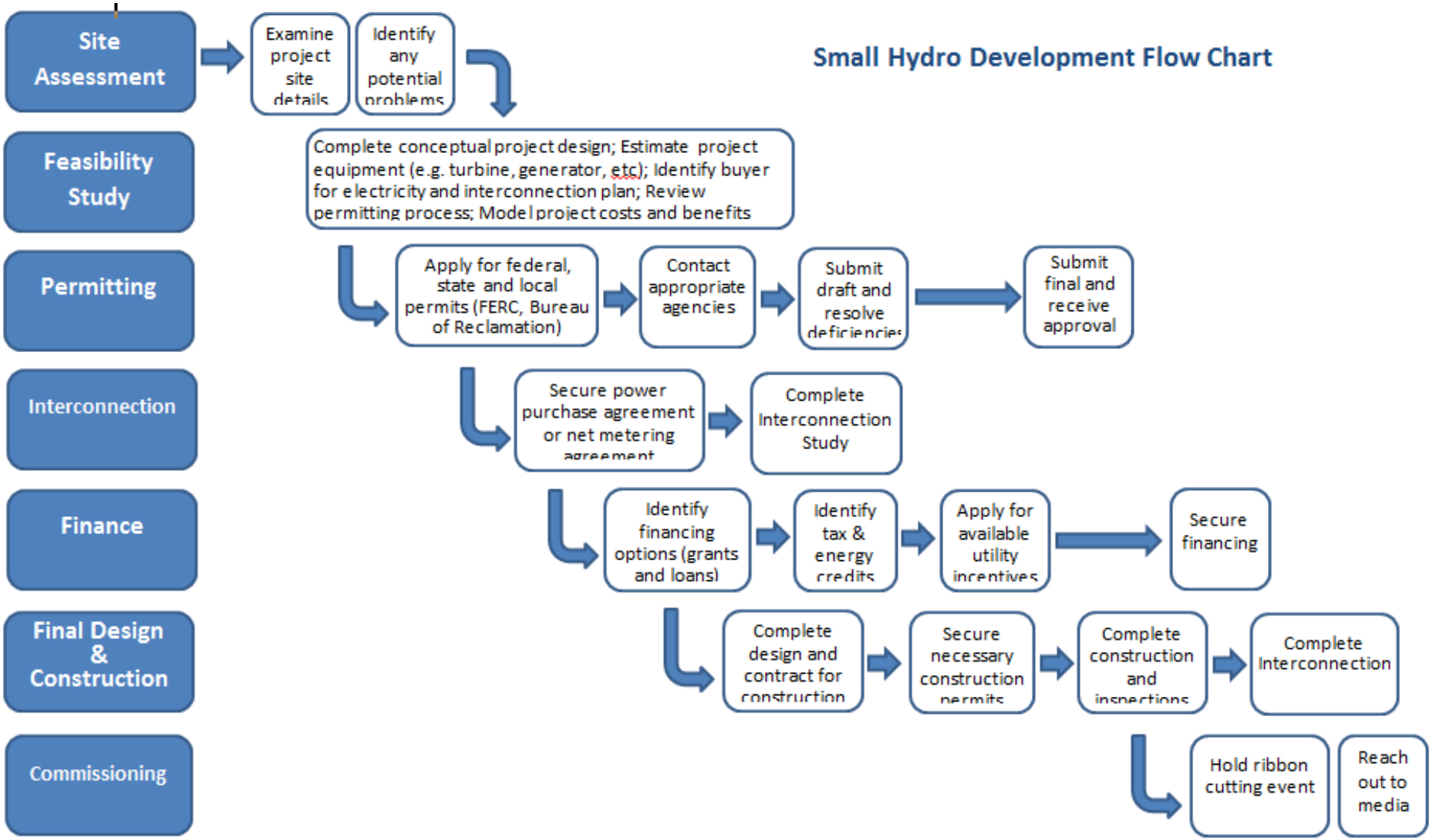

Small Hydro Development Flow Chart
Site Assessment
Examine project site details
Identify any potential problems
Feasibility Study
Complete conceptual project design; Estimate project equipment (e.g. turbine, generator, etc); Identify buyer for electricity and interconnection plan; Review permitting process; Model project costs and benefits
Permitting
Apply for federal, state and local permits (FERC, Bureau of Reclamation)
Contact appropriate agencies
Submit draft and resolve deficiencies
Submit final and receive approval
Interconnection
Secure power purchase agreement or net metering agreement
Complete Interconnection Study
Finance
Identify financing options (grants and loans)
Identify tax & energy credits
Apply for available utility incentives
Secure financing
Final Design & Construction
Complete design and contract for construction
Secure necessary construction permits
Complete construction and inspections
Complete Interconnection
Commissioning
Hold ribbon cutting event
Reach out to media

Introduction

The Colorado Energy Office's (CEO) mission is to promote sustainable economic development through advancing Colorado's energy market and industry in order to create jobs, increase energy security, lower consumer energy costs and protect the environment. The CEO's Small Hydro Program is working to accelerate development of cost-effective small hydropower across Colorado. The purpose of this Handbook is to provide a resource for developers, utilities, agricultural businesses and others interested in developing a small hydropower project in Colorado.

What is Small Hydro

Hydropower is the nation's most reliable, affordable and sustainable energy source. It is also America's largest source of clean electricity, currently accounting for about two-thirds of all renewable energy generation in the United States.[i] With the right federal and state policies in place, hydropower has the potential to grow substantially.

Unlike large hydropower projects, small hydropower projects typically divert a small portion of a river or are constructed on pre-existing diversions and pre-existing dams.[ii] According to the Low Impact Hydropower Institute (LIHI)[iii], in order for a hydropower project to be deemed low-impact, it must meet criteria in areas including minimum river flows, water quality, fish passage, watershed protection, threatened and endangered species, recreation, and cultural resource protection.

There is no widely-accepted definition of the term "small hydropower." For this handbook, small hydropower is defined as meaning development on existing infrastructure or hydropower with generating capacity of 2-megawatts or less.

Colorado's Small Hydro Potential

Colorado currently has numerous hydropower installations. As of 2005, there were sixty-two operating hydropower facilities throughout Colorado with a combined installed capacity of 1,162 megawatts, producing about 1,036,000 megawatt-hours of electricity annually -- with plants ranging in size from 5 kilowatts to 300 megawatts and including three pumped storage facilities.[iv]

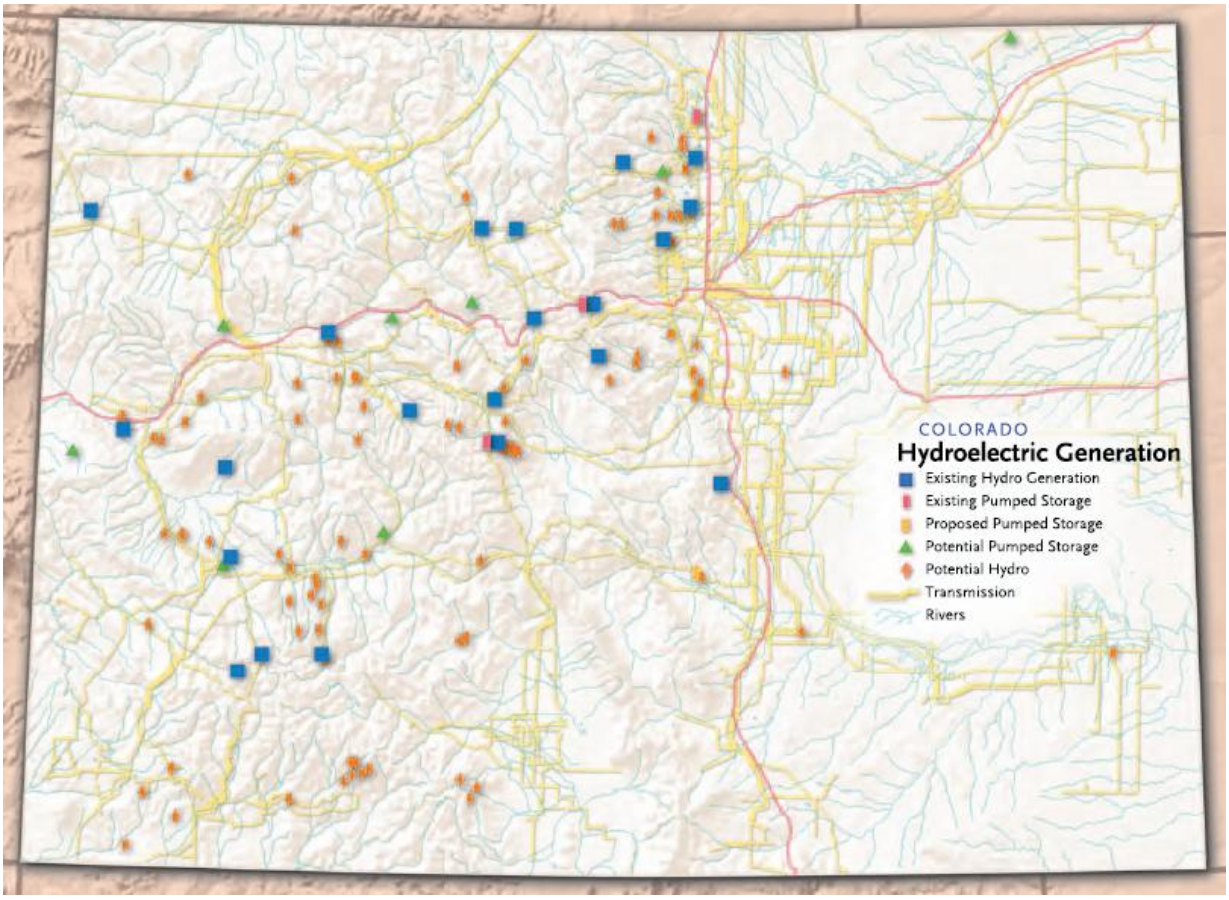


Figure 1: Colorado's Hydroelectric Generation

Source: Colorado Energy Office, Renewable Resource Generation Development Areas Task Force. Connecting Colorado's Renewable Resources to the Markets. December, 2007.

Colorado has additional potential hydropower sites that have not yet been developed. The Bureau of Reclamation and the Department of Energy's Oak Ridge National Laboratory recently completed studies of untapped U.S. hydropower potential utilizing existing infrastructure.

According to the Bureau of Reclamation, Colorado currently has over 30 potential hydropower sites at Reclamation facilities with the potential to produce over 105,000 MWh/year. The DOE report estimates an additional 11 potential sites with the potential to produce over 632,000 MWh/year. Between these two studies, Colorado's estimated untapped hydropower energy potential is over 737,975 MWh/year. If Colorado were to utilize this full potential, it could power over 65,000 homes a year utilizing new hydropower.[v]

Step 1 Site Assessment

The first step in developing a hydropower project is to complete a site assessment in order to determine whether a project site is promising enough to warrant proceeding to the second step, completion of a feasibility assessment. A site assessment typically includes the following:

Step 1A. Site Location, History and Ownership

Factors to consider when evaluating a project site include who owns the site, who owns the surrounding land, and what will the project mean for the surrounding area, including any nearby towns. You will also need to identify the intake, outlet and existing property rights associated with all aspects of the project. It can also be helpful to identify previous owners of the existing infrastructure and understand what alterations have been made since the infrastructure was initially built.

Step 1B. Stream or Body of Water

The purpose of this step is to understand the potential impact of the proposed project on the relevant stream or body of water and to understand the flow available for power generation. You will need to know what water agency (e.g. water district, ditch company, etc.) controls the available water, whether there any diversions upstream that influence flow at the project site.

Step 1C. Water Rights

Water Rights in Colorado are based on the "prior appropriations system", which is often referred to as *first in time, first in right*. Water rights are obtained by applying to the water court and obtaining a decree for a specified amount, location, priority date and use. An absolute water right is one that has been put to beneficial use and that the water court has recognized as valid. A conditional water right is a placeholder in the prior appropriation system that has not been recognized by the water court as being put to beneficial use. A conditional right gives a project proponent time to develop their water right and put it to beneficial use without losing their place in the priority system. A conditional water right must show due diligence towards perfecting the water to an absolute right and is reviewed every six years by the water court for progress.

Beneficial use is the overt act of taking water from a water source and applying it to a specified purpose. Beneficial uses include irrigation, domestic, municipal, industrial and power generation, among others. The CO State Engineer's Office administers water rights and allocates water to water right holders. The most senior water right holders (those that were obtained at the earliest date) are entitled to water available in the river before the junior water right holders, independent of their location along the river. For example, if a junior water right holder is located upstream of a senior water right holder, the water must flow past the diversion point of the junior right to satisfy the holder of the senior right in case there is not

enough water to satisfy both needs. This is a simple scenario; depending on the basin, water rights can be much more complicated. Generally, the more senior a water right, the more certainty there is that water will be available in years of low water supply.

Power generation is generally considered a non-consumptive use, since water is diverted and returned to the river in the same amount, and no water is consumed through the use. There may be an exemption to this if a reservoir is constructed to hold water or a canal feeds the hydropower plant since evaporation may consume a portion of the water diverted. Some rivers and streams in Colorado have minimum flow requirements also known as In-stream Flow Rights. These are water rights held by the Colorado Water Conservation Board for the purpose of maintaining minimum flows in the river. These in-stream rights may be junior to a senior water right holder, but new hydro junior rights need to consider their impact even if the water right is non-consumptive. There may be a portion of the river or stream between the intake and the discharge where in-stream flows cannot be reduced.

In order to divert water from a stream for the purpose of generating hydroelectric power in Colorado, a water right must be obtained with the beneficial use of power generation. However, if water is diverted for another reason such as for irrigation or municipal use -- and hydropower is added to that existing system -- a new water right may not be needed if the timing and duration of diversions are not changed from their previous or historic use. For example, if hydropower was added to the water supply system for a municipality, and water deliveries and diversions were only made to meet the municipal needs of the system while hydropower was generated incidentally, a new water right would not need to be obtained. As an alternative example, if hydropower was added to an irrigation pipeline and new diversions were made throughout the year to supply the hydropower facility -- whereas in the past, diversions were only made during irrigation season -- a new water right would need to be filed for the diversions outside of irrigation season.

Applying for a new non-consumptive water right will typically face less objection than a new consumptive water right, although the process for both is rather complex. The Colorado Division of Water Resources provides guidance, but recommends the assistance of an attorney when applying for the right. There are many attorneys in Colorado that focus specifically on water issues; please see Appendix 1 for a list of resources.

Step 1D. Estimated Head and Flow

During the site assessment, obtaining an initial estimate of head and flow will make it possible to estimate the generation capacity at the site. In the feasibility study stage, these estimates will be refined to take into account system losses and variability in flow. Estimating head at a site requires measurement of the elevation difference between the intake and the

powerhouse. This can be measured with a GPS or estimated from maps such as USGS topographical maps or Google Earth. These methods will be approximate but will be satisfactory at this stage of development. Flow can be estimated from historic measurements or stream gauges (this is discussed in more detail in the feasibility phase below). Once a flow rate and head has been estimated, the following equation can be used to estimate the capacity of a hydropower plant.

$$Power\ (kW) = \frac{Head(feet)\ \times Flow(cfs) \times efficiency}{11.8}$$

Efficiency will be evaluated after the plant configuration is finalized and the turbine selected. At this stage, the efficiency can be assumed between 70 and 80% for a preliminary estimate.

Step 1E. Road Access

It is necessary to understand how all aspects of the project will be accessed by road, including the intake, penstock and powerhouse. When considering road access, be sure to consider if the road is public or private, and if the road is private, consider whether it will be possible to get permission to use the road. Also, be sure the road is large enough for passage of necessary construction equipment. If there is not suitable road access, estimating road construction costs will need to be part of the feasibility assessment.

Step 1F. Distance to Utility Connection

This step requires understanding how electricity generated by the project will be transferred to the local electric grid, either directly or through an existing meter with an adjacent on-site electrical load which can be served by the new hydro plant. You will need to know the distance to the nearest utility distribution or transmission line and what type of line it is, single phase or three phase.

Step 1G. Political, Community or Environmental Issues

It is important to determine early in the development process whether there are likely to be any community concerns associated with the project that may turn into problems later. Seeking to identify and address any problems or project opponents early can help avoid wasting time and money later. Consider whether there are any historical sites in the vicinity, or any commercial and recreational activities that may be negatively affected, or any neighbors that may be able to hear noise from the project site. Also evaluate there are likely to be environmental or aesthetic impacts, including diminished water flows, which could cause objections from anyone.

STEP 2 Feasibility Assessment

If a project appears viable after the initial site assessment, the next step is to complete a full feasibility study. Below is an overview of what a feasibility study typically includes.

Step 2A. General Project Types

There are several types or configurations of small hydropower schemes. A number of common types are described below.

2A1. **Small Hydropower on a Dam**

Dams are generally constructed for water supply purposes, flood control, or recreation. Depending on the type of dam and the outlet configuration, several alternatives are available for hydropower development. A general schematic of hydropower on a dam is shown below in Figure 2.

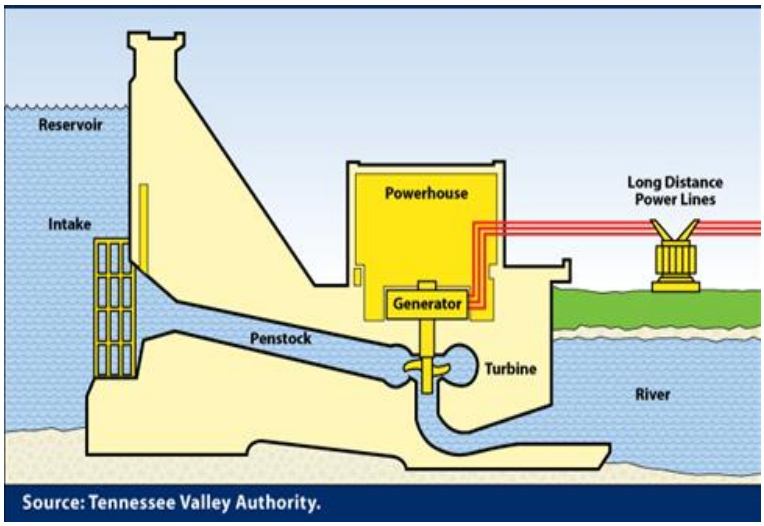


Figure 2: Schematic of a Hydroelectric Dam

Photo courtesy of Tennessee Valley Authority

i.) **Existing Dam: Carter Lake**

The Carter Lake Hydroelectric Project was constructed in 2012 by the Northern Colorado Water Conservancy District. It consists of two 1.3 MW Francis turbines. The turbines utilize 147 feet of head and 125 cfs each. The project was constructed on a secondary outlet from the reservoir. Using a secondary outlet creates redundancy, which in turn allows the dam to function as intended with the primary outlet if for any reason the hydropower plant cannot supply water downstream.

Figure 3: Carter Lake Turbines

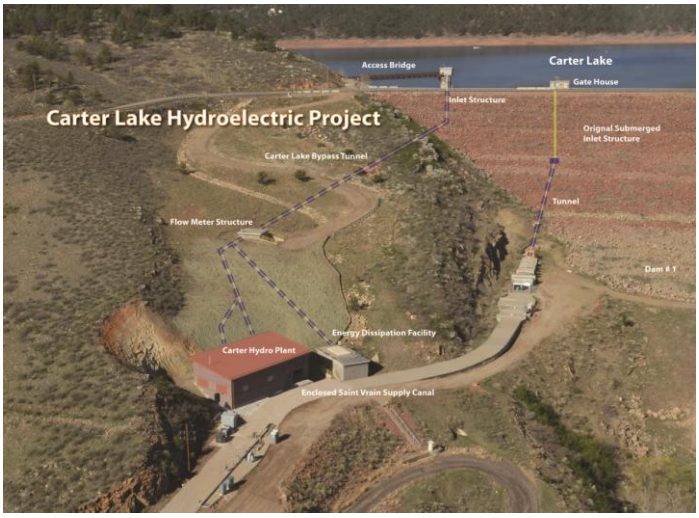


Figure 4: Schematic of Carter Lake

Photos courtesy of Northern Colorado Water Conservancy District

ii.) **Siphon penstock: Humphreys Hydro Project**

Another alternative for building a hydropower plant on a dam is to use a siphon penstock over the dam instead of an outlet through the dam. This alternative may be preferred if the existing outlet to the dam is not adequate for the pressures or flow rates required. There is a limit to the maximum theoretical lift between the reservoir water surface and the top of the siphon that needs to be considered in the design. The Humphreys Hydroelectric project near Creede, CO is an example of a project with a siphon penstock. This project was constructed by a private landowner. It consists of one 310 kW Cross Flow turbine using 91 feet of head and 60 cfs of flow.

Figure 5: Humphreys Hydro Powerhouse

Figure 6: Humphreys Hydro Siphon Intake

iii.) **Spillway/other outlet**

Some dams may provide an opportunity to use the existing spillway. The capacity of the spillway needs to be maintained for safety and flood protection, but it may be an alternative worthy of exploration. The Catamount project on Lake Catamount is an example of such a project that is still in the planning stages. This project would use 37 feet of head and 280 cfs of flow to generate 695 kW of power with a Kaplan turbine.

Figure 7: Lake Catamount Spillway

2A2. **Run-of-the-River Hydropower**

Run-of-the-river hydropower is a term to describe a hydropower plant which diverts water from a watercourse through a penstock and powerhouse, and returns the water back to the watercourse downstream, as shown in Figure 8.

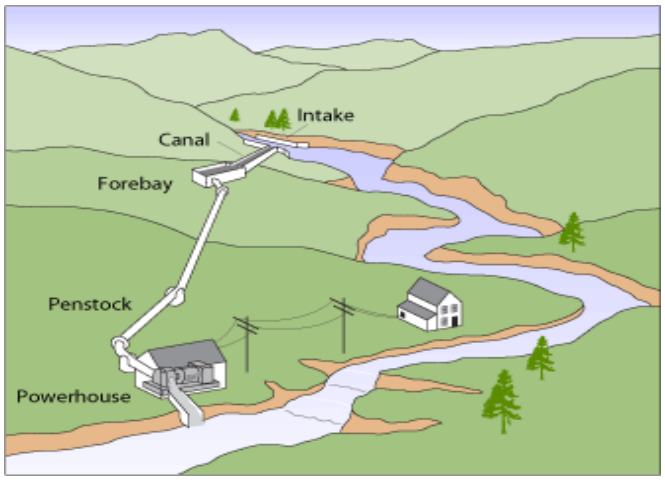


Figure 8: Run-of-the-river Schematic

Figure courtesy of US DOE

i.) **Diversion for hydropower only**

The Maroon Creek Hydropower plant in Aspen is an example of a run-of-the-river hydropower plant where the multipurpose diversion is used for supplying flow to the hydropower plant. The diversion is located on Maroon Creek and diverts up to 60 CFS. The water then passes through a 450 kW Cross Flow turbine. Water diverted from Maroon Creek at that location can also be sent on to Thomas Reservoir and into the city's municipal water system.

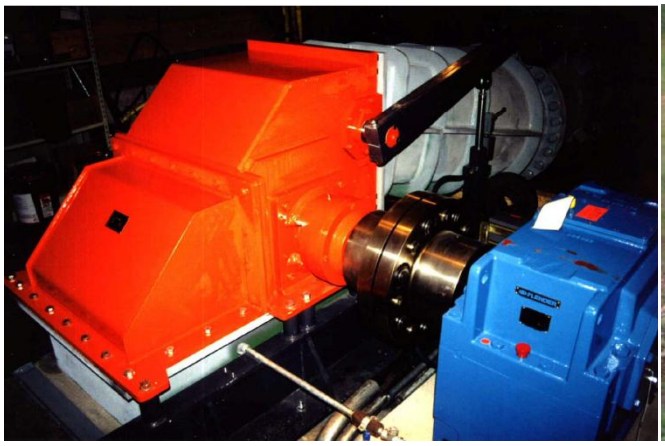


Figure 9: Maroon Creek Turbine

Figure 10: Maroon Creek Intake

ii.) **Using an existing diversion**

Run-of-the-river hydropower may also be installed on a diversion and canal that exists for another purpose. One such example in Colorado is the Grand Valley Power Plant on the Orchard Mesa Irrigation District irrigation system. Flows for the hydropower plant and the irrigation system are diverted from the Colorado River though a canal. Hydropower flows are discharged back into the river downstream while irrigation flows continue through the canal. Two Kaplan turbines produce 3 MW of power using 79 feet of head and up to about 300 cfs of flow each.

Figure 11: Grand Valley Power Plant Turbines

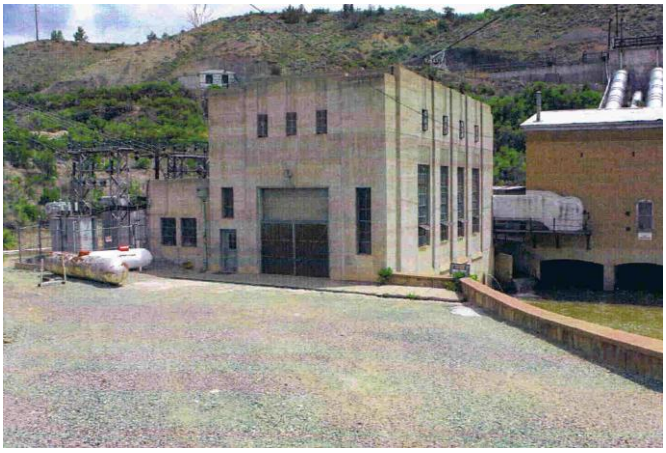


Figure 12: Grand Valley Power Plant Powerhouse

2A3. **Conduit Hydropower**

Conduit hydropower uses a conduit (pipe or canal) that exists for another purpose, such as municipal water supply or irrigation. Power can be generated from excess pressure in the pipeline that otherwise would have to be mechanically reduced by pressure reduction valves. This type of hydropower plant is generally very cost effective due to the utilization of existing infrastructure.

i.) **Water Supply system**

Municipal water supply systems that are located in or near mountains may be fed by gravity. The water supply reservoir is commonly located at a higher elevation than the water treatment plant and water flows downhill by gravity. In many cases, this results in excess pressure at the water treatment plant; this pressure is either used in the treatment process or reduced using a pressure-reducing valve. When this excess pressure is not needed, it provides an opportunity for hydroelectric generation. This is the case at the Project 7 water treatment plant near Montrose. The pressurized water from the water supply reservoir is passed through the turbines instead of the pressure-reducing valves, producing power that offsets the water plant's electrical demand. The system consists of two different turbines, one 90 kW and one 60 kW, allowing for a larger variation in flow. The plant utilizes up to 132 feet of head and between 7 and 17 cfs of flow depending on the season.

ii.) **Irrigation System**

Irrigation system pipelines offer an opportunity for hydropower development if excess pressure is available. The Wenschhof project utilizes an existing pipeline to feed a 23 kW Pelton turbine. The turbine uses 160 feet of head and up to 2 cfs to produce power during irrigation season. The power produced is used to offset the demands of the irrigation system and other demands on the ranch.

Figure 13: Wenschhof Turbine

Figure 14: Wenschof Intake

iii.) **Wastewater outfall**

Wastewater outfalls may provide hydroelectric opportunities if a significant elevation drop is available. Currently this type of hydropower plant does not exist in Colorado. Large municipalities with a large wastewater treatment plant may have the elevation drop and flow rate necessary at their wastewater treatment plant to produce a significant amount of power.

iv.) **Low Head canal**

The Redlands Canal provides irrigation water to a portion of Grand Junction. The hydropower plant is located on a low head drop within the canal, created without a pipeline. The Kaplan turbine was installed in the early 1900s and produces 1.6 MW using 690 cfs and 30 feet of head.

Figure 15: Redlands Powerhouse

Figure 16: Redlands Turbine

2A4. **Hydrokinetic**

Hydrokinetic turbines are a relatively new type of turbine technology. Pilot installations are being tested in river, canal, and tidal flows. Hydrokinetics produce power from the velocity of the water instead of using pressure. This design results in a relatively low output power facility that needs very high flows. The concept is similar to a wind turbine, but underwater. Currently there are no hydrokinetic installations in Colorado.

i.) **Canal**

The canal installation shown below is a Hydrovolts turbine installed in the Roza Canal in Oregon. This was a test installation in operation for 6 weeks. The turbine produces 5 kW with 6.5 ft/sec of flow velocity. The canal is 14 feet wide at the bottom with a maximum water depth of 11 feet. The canal flows between 1,100 and 2,100 cfs. The installation of this turbine requires little civil infrastructure, although the canal must have adequate geometry and

freeboard to handle the resulting rise in water surface elevation upstream of the turbine (6”-8” in this case).

Figure 17:Hydrovolts – Roza Canal

Photo courtesy of Hydrovolts

ii.) **River**

Hydrokinetic river installations can be installed by anchoring to a structure, such as a bridge or to the bottom of the riverbed. This example is a floating barge attached to the bridge in Manitoba, Canada. The turbine was in place for less than a year and removed prior to the river icing. This is a 5 kW turbine, requiring velocities of more than 6.5 ft/sec. The turbine is 7.5 feet tall and 5 feet in diameter.

Figure 18:EnCurrent – Manitoba, Canada

Photo courtesy of New Energy Corp

2A5. **Hydro-mechanical**

A less frequently used, but very traditional method of hydropower development is to use water power to turn mechanical machinery. No electricity is produced by these plants; the turbine simply turns the rotating machinery to do mechanical work. Historically hydro-mechanical

plants were used to power sawmills, textile mills, or grain mills. Below are two examples of operating hydro-mechanical plants in Colorado: one used to pump water and the other to power an irrigation sprinkler system.

The Bear River Ranch hydro-mechanical irrigation system is discussed in more detail in the attached case study: a turbine powers a hydraulic pump which moves the center pivot sprinkler system. 126 feet of head and 850 gpm provides the equivalent of 21.5 HP to the hydraulic pump.

The Orchard Mesa Pumping Plant uses the power of falling water to pump water to a higher elevation. The turbine and pump shafts are coupled to operate together. This plant was constructed at the turn of the century and has been in continuous operation since. Four pumps supply up to 150 cfs to two canals, one at 130 feet above the inlet canal and one at 41 feet above the inlet canal. The turbines use over 200 cfs of water falling 74 feet to produce the equivalent of 1.1 MW of energy. The pumping plant is located directly adjacent to the Grand Valley Power Plant mentioned earlier.

Figure 19: Bear River Ranch turbine

Figure 20: Orchard Mesa Pump Plant

Step 2B. Head and Flow

During site assessment, an estimate of head and flow has been made to approximate the plant's generating capacity. During the feasibility phase, a more accurate measurement of head and flow must be made to calculate the annual energy production and to size the system accurately.

2B1. **Hydrology**

Flows available to a hydropower plant can be estimated using the hydrologic conditions of the site or flows can be physically measured. The choice of method will depend on the available data. Methods and resources will be described below to calculate present or historic hydrologic conditions. When using these methods, keep in mind that available flows can change

due to meteorological conditions. Forecasting future available flow requires careful consideration of past drought conditions and current climactic trends. Please see Appendix 2 for more Colorado hydrology resources.

i.) **Historic Hydrology Data**

There are several resources for calculating the flow that will be available to a small hydropower plant.

Existing Diversions:

In instances where water is already diverted from a stream for agricultural, municipal or industrial uses under an existing water right, historic records of diversion may be available. The joint efforts of the Colorado Water Conservation Board (CWCB) and the Colorado Department of Water Resources (DWR) maintain the Colorado's Decision Support Systems (CDSS) database, which among other things, provides Historic Diversion Records and Streamflow Stations data. The CDSS website offers users the ability to search for diversion records using multiple criteria, such as by diversion name, water source, owner's name, and legal location. Streamflow Stations can also be searched using multiple criteria, such as by station name or county. In many cases, the database provides free downloads of daily records and/or yearly averages of flow data. Use of this data can be helpful when estimating water availability annually or at different times of the year.

New Diversions:

In cases when the hydropower facility will be utilizing a new diversion, water availability may be approximated by using flows from nearby stream gauges. Typically, gauges are located along the mainstem of rivers, although in some instances they may also be used to monitor ditches. If the proposed hydro site lies in close proximity to an operational stream gauge, that data can be applied to the proposed site. Average flows over multiple time periods can typically be accessed through the U.S. Geological Survey database (USGS) or the Colorado Division of Water Resources database (DWR). It is important to check for tributary, diversion, or other disruptions to flows between the known stream gauge and the proposed hydro site and adjust flow data to obtain a reasonable flow estimate. Figure below was created using stream gauge locations along the Eagle River, obtained from the DWR website.

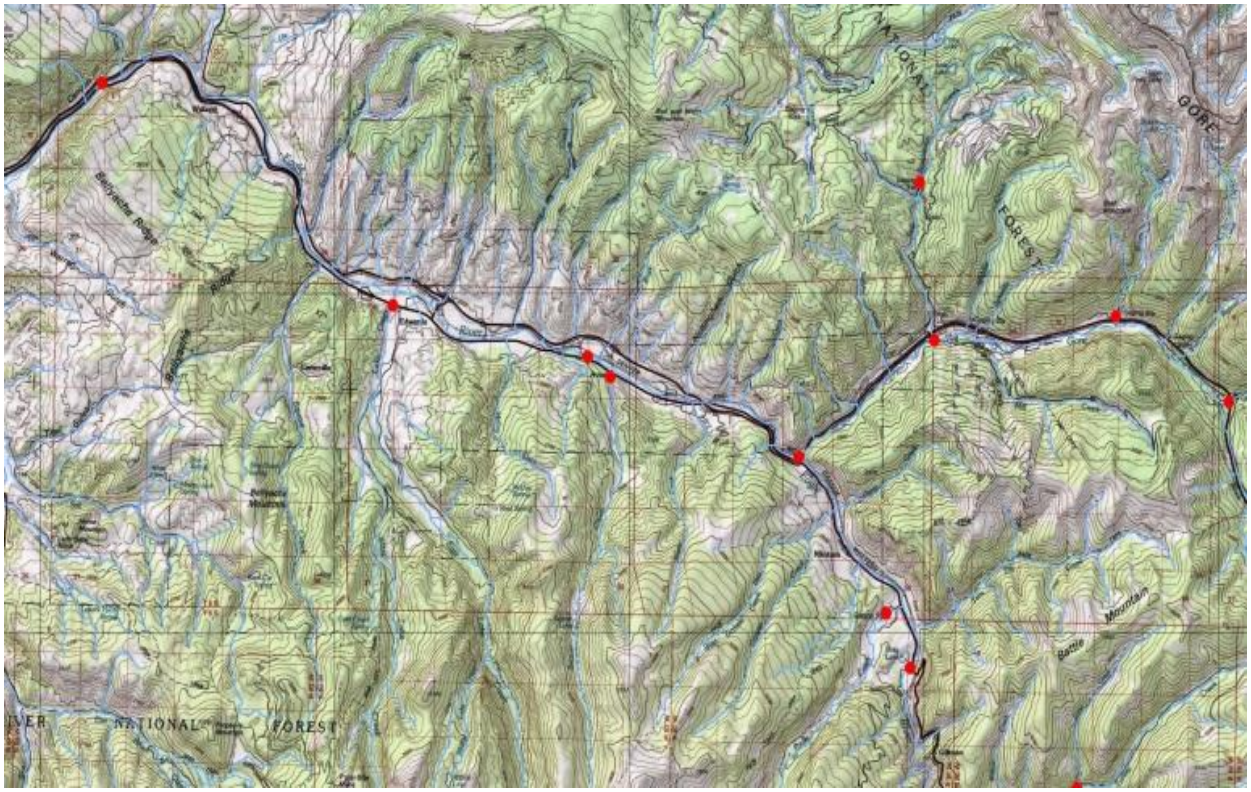


Figure 21: Stream Gauge Locations

Source: Colorado Division of Water Resources

ii.) **Measurement of Flow**

If historic records do not exist, it may be necessary to measure flow for a period during the planning stages of a hydropower plant. There are many structures to measure the flow rate in a channel. The United States Bureau of Reclamation (USBR) has a free on-line publication entitled "*Water Measurement Manual*" which serves as a helpful reference for various methods of flow measurement. By using the structure's dimensions, in conjunction with flow depths, a flow rate can be determined by referencing tabulated flow discharge values. Such tables can be obtained from various sources. The USBR manual has tabulated data in its Appendices for three, commonly used flow measurement structures: the Parshall Flume, the weir, and the flow meter.

a) Parshall Flume

The Parshall Flume is one of the most common types of flume used in Colorado, depicted in Figure 22. Generally, canals are metered using this type of flume. Use of a flume is likely the best alternative for flow measurement when water depth is low. For this particular type of measurement structure, a flume of known geometry is installed perpendicular to the flow in a channel. Using the measured water depth and throat width in the flume, an associated flow

discharge can be calculated or obtained through reference to flow discharge tables (located in Appendix A8 in the USBR Water Measurement Manual)

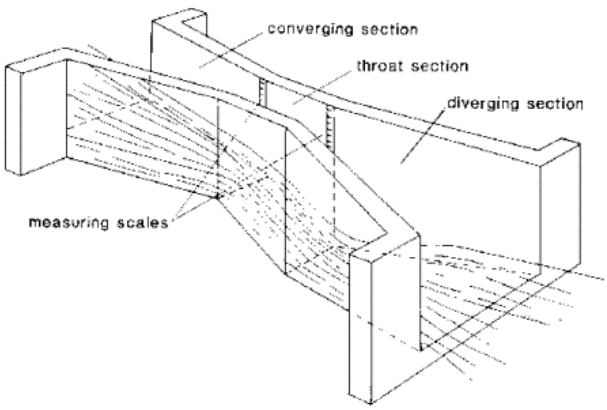


Figure 22: Parshall Flume Schematic

Photo courtesy of the Food and Agriculture Organization of the United Nations

Figure 23:Parshall Flume in Box Elder Ditch, Cache la Poudre

Photo courtesy of the Poudre Heritage Alliance

b) Weir

A weir is an overflow structure of known dimensions, installed perpendicularly in the channel to measure the flow rate, as viewed in Figure 24. The Sharp-crested weirs show in Figure 25a have a center notch of varying shapes through which water will be directed, while broad-crested weirs in Figure 25b have a horizontal crest over which water will flow. Using the upstream pool depth, weir dimensions, and depth of water flowing over the weir, the discharge flow rate can be calculated or obtained from a table. Appendix A7 in the USBR Water Measurement Manual provides discharge tables for the more common types of sharp-crested weirs.

Figure24: Cipoletti Weir

Photo courtesy of the USBR Water Measurement Manual

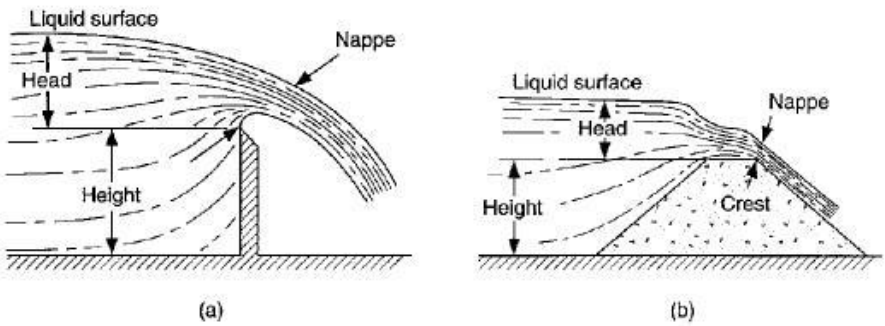


Figure 25: Types of Weirs

Figure courtesy of the USBR Water Measurement Manual

c) Flow meter

There are multiple types of flow meters. The most commonly used type is the submerged orifice flow meter, shown in Figure 26 and Figure 27. It consists of a precisely defined, sharp edged opening placed perpendicularly to the channel flow, through which all water passes. As small changes in the orifice's construction can have a large impact on the accuracy of its associated flow values, it is imperative that the orifice be well-machined and dimensioned as accurately as possible. By measuring the water depth immediately upstream and downstream of the orifice, flow rate can be obtained through use of discharge tables. Appendix A9 of the USBR Water Measurement Manual provides discharge tables for commonly used orifices.

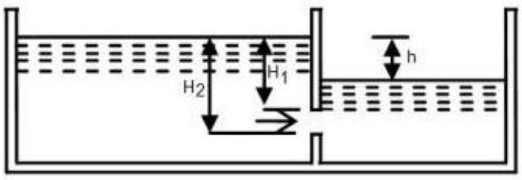


Figure 26: Submerged Orifice Flow Meter

Figure courtesy of USBR Water Measurement Manual

Figure 27: Constant Head Orifice Turnout

Photo courtesy of USBR Water Measurement Manual

d) Current Meter/Velocity Meter

Flow measurement with a velocity meter measures the velocity of the channel flow. It involves the placement of a current meter at specific cross-section intervals along a reach of channel and taking an average flow over those sections. Optimally, current meters should be used in straight, uniform sections of the channel reach in order to minimize flow disturbances.

Additionally, the flow velocity should be greater than 0.5 feet per second and the meter should be kept as still as possible. This type of flow measurement is ideal for investigation of larger flows or for flows containing larger amounts of sediment. There are multiple types of current meters to measure the velocity of the channel flow:

1) The anemometer and propeller velocity meter is shown in Figure 28. This type of current meter is commonly used for irrigation and watershed applications. It measures velocity by dragging anemometer cup wheels or propellers through calm waters.

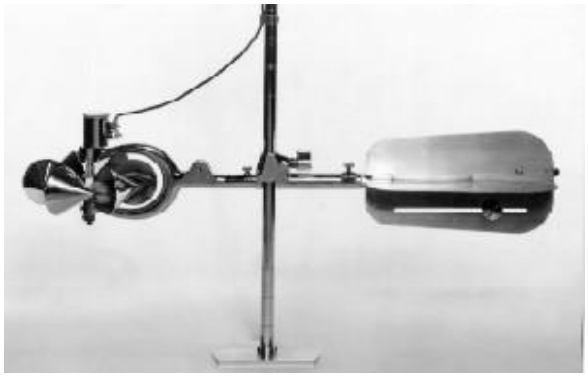


Figure 28: Anemometer and Propeller Current Meter

Photo courtesy of USBR Water Measurement Manual

2) The electromagnetic velocity meter is shown in Figure 29. This type of current meter produces voltage proportionately to the stream velocity and has an easily read analog display. It is able to account for directional velocities and measure cross flows but is not as accurate as anemometer-propeller current meters.

Figure 29: Electromagnetic Current Meter

Photo courtesy of Valeport, Ltd.

3) The doppler velocity meter is shown in Figure 30. These meters measure the change in source light or sound frequency to measure velocity. Electromagnetic current meters are versatile, providing measurement in a wide range of water body sizes and types. They are able to measure multiple directions of flow velocity simultaneously.

Figure 30: Doppler Current Meter

Photo courtesy of SonTek

iii.) **Flow Duration Curve**

Stream gauges, such as that depicted in Figure 32, are located in many waterways. The gauges generally consist of a water level sensor which logs the elevation of the water on a daily, hourly, or sub-hourly basis. The section of stream will have been studied previously and a relationship between the water surface elevation and the total flow is known. The flow is measured by monitoring the water level. The variance in annual flow can then be depicted graphically, such as in Figure 31. Use of this data can allow for more accurate small hydro planning by enabling consideration of maximum and minimum flows and observing trends in consecutive yearly data.

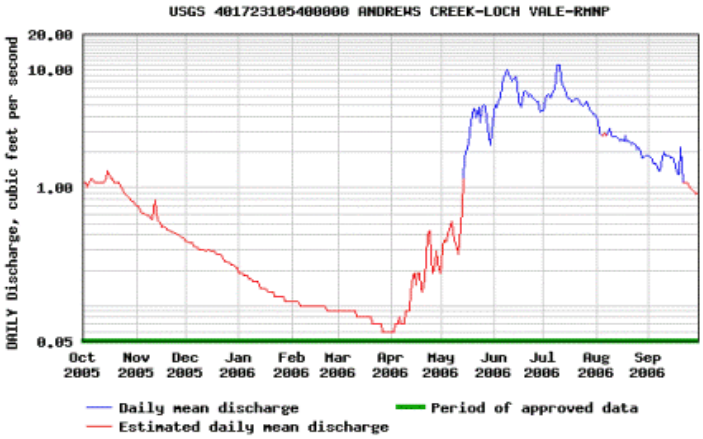


Figure 31: Annual Discharge Graph for Andrews Creek, CO

Figure courtesy of the USGS Colorado Water Science Center

Figure 32: Stream Gauge on Andrews Creek, CO;

Photo courtesy of the USGS Colorado Water Science Center

From stream gauge data or historic flow records, a flow duration curve (FDC) like that shown in Figure 33 can be developed. An FDC will graphically represent flow probability based on magnitude. FDCs depict the relationship between channel flow and the percentage of time that specific flow rates were met or surpassed. If the majority of the FDC is a steep slope, the curve is indicative of a channel that is highly variable throughout the year and largely dependent upon surface runoff. For a curve that has a relatively flat slope, it can be concluded that the channel for which it relates has a recharge sourced from surface water or ground water. A flat slope at the end of the curve is characteristic of a large amount of storage associated with the channel; conversely, a steep slope is indicative of a negligible amount.

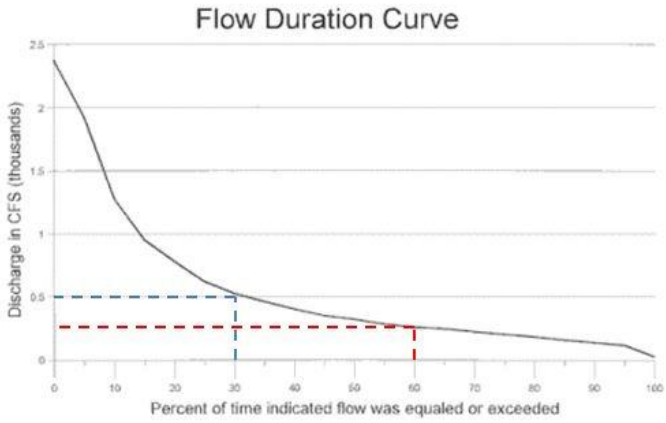


Figure 33: Flow Duration Curve with 30% & 60% Exceedance Indication

Figure courtesy of Missouri Department of Conservation

a) How to select the design flow using this curve

The FDC enables the assessment of flow variability at the proposed hydro site and the determination of an initial design flow for the hydropower system. The design flow is the flow at which the turbine operates most efficiently and is the maximum flow rate that the hydro system should operate at for an extended period of time. When looking at a FDC, an initial estimate of the design flow for a small hydro system will typically be the flow associated with an exceedance value between 30% and 60%. For the example FDC above, the design flow at 30% exceedance and 60% exceedance would be approximately 500 cfs and 250 cfs, respectively. Developing the system for a design flow with an exceedance of 60% means that the system would run at design capacity for approximately 60% of the year and somewhat less than that value for the remaining 40% of the year. This is a more conservative design than would be reached were a 30% flow exceedance used as the design flow since the flow will only be at this maximum 30% of the time.

Once a general range of potential design flows is obtained, the Turbine Selection Chart shown below will provide an initial selection of turbines most suited to the range of design flow. In order to size the system appropriately, each system will have to be analyzed individually and the costs and benefits compared among potential turbines. Generally the design flow can be exceeded by approximately 10%; however, running the turbine at this higher flow rate should not be a frequent occurrence as turbine efficiency will decrease and excessive wear or damage on the turbine or components may result.

b) How to use multiple turbines

Multiple turbines can be combined in a hydro system to achieve a desired design flow, allowing for more flexibility in production. Two of the same type of turbine having different size capacities can be used in conjunction to cover a larger range of discharge at a hydro site. An example situation constituting an appropriate use of multiple turbines is when there is a significant variation in flow seasonally. If winter flows are very low, it may make sense to use a smaller turbine that operates in the winter, and a larger turbine to capture the spring, summer, and/or autumn flows as shown in Figure 33. Another pertinent application of multiple turbine usage may be if a standard turbine size, such as a pump used as a turbine, cannot accommodate the design flow; several turbines may be used in parallel to compensate as shown in Figure 34.

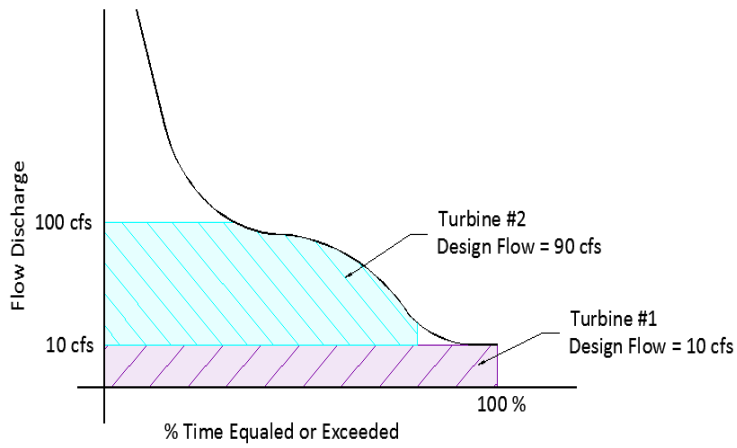


Figure 34: Flow Duration Curve Depicting Two Turbine System

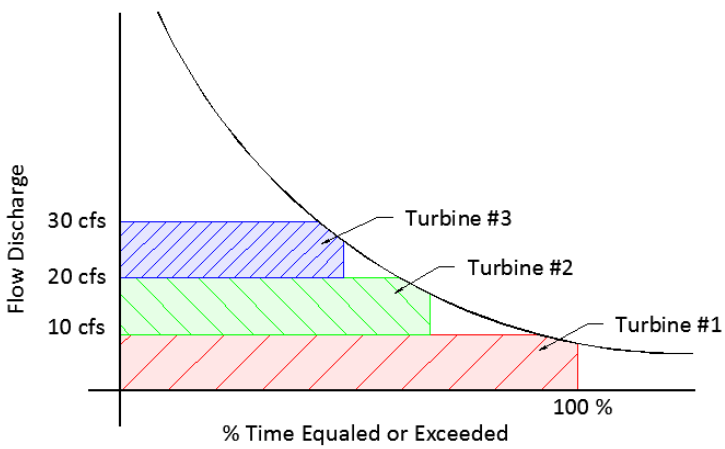


Figure 35: Flow Duration Curve Depicting Three Turbine System

iv.) **Head**

Head is representative of the water pressure at a hydro site. The term "head" can be applicable to two different values. The *gross head* is quantified by the change in water elevation between the top and bottom of the vertical drop, prior to the commencement of any water flow (see Figure). However, because energy is lost when converting from one form to another, the available head for integration into the hydro system's design must be adjusted to account for energy loss that occurs as the water navigates the penstock. The resulting adjusted head, called the *net head,* represents the pressure at the bottom of the pipeline during water flow after accounting for any energy loss that occurs in the penstock. The net head in a well-designed system will generally be 85-90% of the gross head value. The net head is important, as it represents the actual amount of head available for use in the turbine. It should be noted that energy loss in the penstock has the same effect on a hydro system as if the gross head

were lowered; therefore the terms “energy loss” and “head loss” are synonymous in penstock applications. The relationship between gross head and net head is as follows:

$$\begin{matrix}\text{Gross}\\\text{Head}\end{matrix} - \begin{matrix}\text{Head}\\\text{Loss}\end{matrix} = \begin{matrix}\text{Net}\\\text{Head}\end{matrix}$$

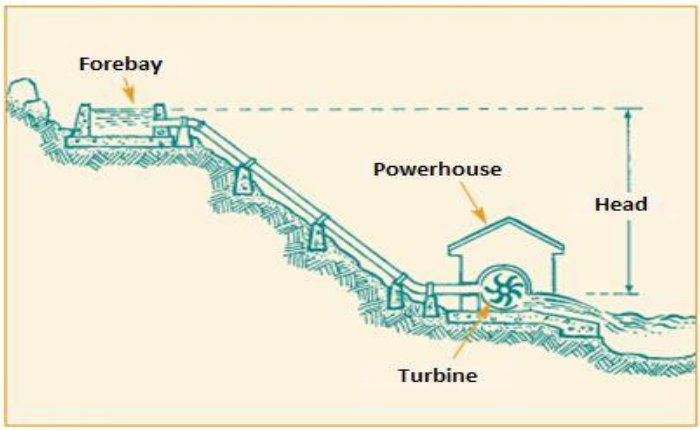


Figure36: Gross Head of a small hydro system
Figure courtesy of Micro-Hydropower Systems, A Buyer’s Guide; Natural Resources Canada

Total energy loss in the penstock resulting in decreased net head can be divided into two categories: friction losses and minor losses. Friction loss in the penstock is a function of penstock diameter and length, flow rate, water pressure, and pipe composition. An increase in penstock diameter will reduce friction losses. Alternately, as water pressure, flow rate, and/or penstock length increase, losses resulting from friction will increase as well. Some pipe materials will result in a greater head loss due to increased pipe friction. Penstock material options will be addressed in more detail below. Minor losses in the penstock are attributable to any bends, fittings and valves and the penstock entrance. The total energy loss can be quantified as follows:

$$\begin{matrix}\text{Total Energy}\\\text{Loss}\end{matrix} = \begin{matrix}\text{Friction}\\\text{Losses}\end{matrix} + \begin{matrix}\text{Minor}\\\text{Losses}\end{matrix}$$

a) Estimate gross head from survey or topographical maps

Elevations derived from survey data or topographical maps, such as those produced by the USGS, can be useful in estimating the gross head available at a hydro site. Typically, an estimate using topographical maps is most effective for high-head sites, as the distance between contour lines can vary depending upon the mapping available in the area. The contour intervals in the example shown in Figure below are occurring at every 40 feet of elevation change. Using the elevation data, the elevation difference between the upstream

point of the drop and the downstream point of the drop is the gross head. For low-head hydro applications, gross head can vary significantly dependent upon the current river conditions. To accurately obtain the available gross head, the headwater and tailwater levels need to be measured with more exact methods over the full range of channel flows.

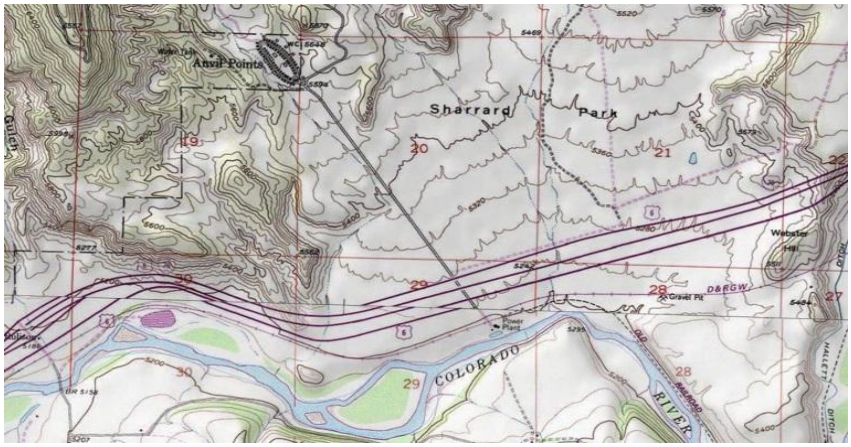


Figure 37: USGS Topography Map, See Appendix 3 for more resources on Colorado Topography

Photo courtesy of USGS

b) Convert pressure to head

Gross head can also be calculated using some type of pressure meter, such as a piezometer or pressure gauge. By utilizing a pipe or tube completely filled with water that spans the full elevation drop, pressure can be measured at the bottom of the outlet. Each psi of pressure accounts for approximately 2.31 feet of vertical head. When using this method, it is best to use a continuous pipe or tube although segments can be used if care is taken to eliminate any leakage at the connections. If a single span of tubing is unavailable, multiple readings can be taken along the elevation drop; however, this method will greatly increase chances for error. Since there is no water flowing out of the pipe when this pressure measurement is taken, it is a measure of the gross head.

c) Estimate head loss at varying flow rates

Flow rate is one of multiple variables in the design of a penstock that can significantly affect head loss. Equations can be used to estimate head loss based upon water velocity, pipeline length, diameter, and material. Engineeringtoolbox.com has a Calculator for head loss in pipes, in which flow rate, pipe diameter and length are input to obtain approximate head loss. A *Pipeline Resistance Curve* may be consulted for head loss estimation as well. As is evident from the Pipeline Resistance Curve depicted in Figure, head loss increases with increased flow rate. For example, a flow rate of 240 gpm would cause approximately 12 feet of head loss in the hydro system used to create the Curve. Pipeline Resistance Curves are created through the

completion of multiple head loss calculations, which require the specification of a general range of flow velocity, penstock material, and pipe length and diameter. The most accurate Pipeline Resistance Curve to use will be that which is applicable to specific site conditions. See Appendix 4 for more resources on head loss.

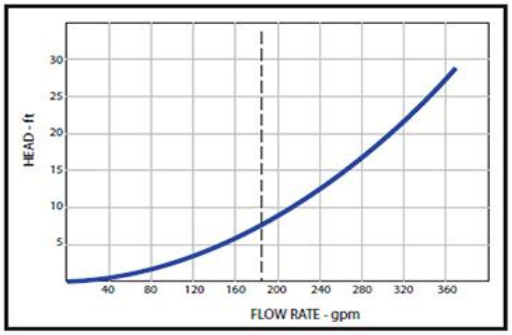


Figure 38: General Pipeline Resistance Curve

Figure courtesy of Engineered Software, Inc.

Step 2C. Penstock Selection

2C1. **Using existing infrastructure**

The penstock can frequently constitute the most expensive component of a hydro system so achieving an optimal design between material cost and energy losses in the penstock should be thoroughly analyzed. In cases where a penstock is already present, it may be possible to use the existing infrastructure rather than constructing a new pipe; however, the potential for reuse is dependent upon whether the pressure rating and the condition of the existing pipe is acceptable. Having the pipeline inspected by a qualified engineer can aid in the determination of suitability. The existing pipeline will also have to be evaluated for friction losses. The original design of the pipeline may not have minimized friction losses and it may significantly affect the amount of head available for hydropower generation.

Figure 39: Deteriorated Penstock

Photo courtesy of Canyon Hydro

i.) **Sizing the penstock**

As mentioned in the previous section, the losses occurring in the penstock have the potential to significantly affect the power available to the turbine. When sizing a penstock, pipe length and diameter, design flow, and gross head must be considered as they contribute to the head loss in the system. In general, the pipe length, design flow and gross head are fixed variables, meaning they are unalterable. As such, the primary alternative to reduce head loss in the system is to adjust the penstock diameter to minimize the velocity in the pipe, and thus, the friction created. However, an increased penstock diameter leads to additional material cost; therefore, an optimum balance should be considered between the two.

When sizing a penstock, a good place to start is calculating a rough diameter of pipe that would adequately pass a flow velocity of 10 feet per second (fps). The flow velocity can be calculated by dividing the flow rate by the area of the pipe opening, taking care to ensure that units are identical. When beginning the design process with an initial 10 fps flow velocity, this relationship can be used to obtain a preliminary inside pipe diameter.

Once an initial pipe diameter is reached, head loss analysis can take place to further refine the penstock sizing. According to Canyon Hydro, a good rule of thumb is to size the pipe such that no more than 10% to 15% of the gross head is lost due to pipe friction. Canyon Hydro released a *Head Loss Chart* (Table 1) that serves as an example for the determination of an appropriate preliminary penstock size, using the example following the table to show how to use the Chart. It can be seen that the chart is not all-inclusive; additional calculations can be made outside of the range shown here.

Table 1: Head Loss Chart

Design Flow														
GPM	0.25	0.5	100	150	200	300	400	500	600	700	800	900	1000	1200
CFS	0.05	0.1	0.2	0.33	0.45	0.66	0.89	1.1	1.3	1.5	1.78	2	2.23	2.67
Pipe size and loss per 100 feet														
2"	1.28	4.65	16.8	35.7	60.6	99.2								
3"	0.18	0.65	2.33	4.93	8.36	17.9	30.6	46.1	64.4					
4"	0.04	0.16	0.57	1.23	2.02	4.37	7.52	11.3	15.8	21.1	26.8	33.4		
6"		0.02	0.08	0.17	0.29	0.62	1.03	1.36	2.2	2.92	3.74	4.75	5.66	8.04
8"				0.04	0.07	0.15	0.25	0.39	0.5	0.72	0.89	1.16	1.4	1.96

Table courtesy of Canyon Hydro

Example site characteristics:

- Gross Head = 100 feet
- Pipeline length = 400 feet
- Acceptable Head Loss = 10% to 15% = 10 feet to 15 feet
- Design Flow = 200 gallons per minute = 0.45 cfs

For the above example, the maximum acceptable head loss would be 15 feet (15% of the 100-foot gross head), which equates to 3.75 feet of head loss for every 100 feet of the 400-foot pipeline. Beginning with the design flow of 200 gpm and following the column down, it is discovered that a 4-inch-diameter pipe is the smallest diameter that provides a head loss not exceeding the maximum of 3.75 feet.

Using a four-inch pipe, the associated head loss would be:

- Head Loss = 2.02 feet (per 100 feet) x 4 = 8.08 feet

Therefore, net head would be:

- Net Head = 100 feet – 8.08 feet = 91.92 feet

In looking at the Head Loss Chart, it is also evident that a six-inch-diameter pipe would decrease friction losses further, thereby providing more power to the turbine; however, the tradeoff must be weighed between increased power and increased pipe cost.

ii.) **Alignment**

In the event that a new penstock must be constructed, ideally it will be as short and straight as possible. In doing so, material and installation costs are reduced and the loss of power resulting from internal friction will be reduced, thereby conserving as much energy as possible. Figure 41 illustrates the preference of slope alignment. Ideally, the penstock will have a consistent rate of decline. A penstock can be either above ground, or below ground. Burying the penstock may facilitate the achievement of an appropriate slope and protect it from damage. Proper anchoring of both buried and above ground penstocks is required to ensure movement does not occur under any conditions, particularly at points of direction change. Each penstock will need to be evaluated individually to determine the need for anchoring and thrust blocks.

Figure 40: Buried Penstock

Photo courtesy of R.G. Parkins & Partners Ltd.

Figure 41: Penstock Slope

Figure courtesy of Home Power

iii.) **Material selection**

For small hydro applications, there are multiple options for penstock material composition, with pros and cons associated with each. The table below lists potential materials for penstock composition, with mild steel, polyvinyl chloride (PVC), high-density polyethylene (HDPE) and medium-density polyethylene (MDPE) being the most commonly used materials. Each material has been assigned a number ranging from 1 to 5, with 1 being poorly rated and 5 being excellently rated. More specific material characteristics are provided below.

Table 2: Penstock Material Composition

Penstock Material Options						
Material	**Friction Loss**	**Weight**	**Corrosion**	**Cost**	**Jointing**	**Pressure**
Ductile Iron	4	1	4	2	5	4
Concrete	1	1	5	3	3	1
GRP	5	5	3	1	4	5
Mild Steel	3	3	3	4	4	5
PVC	5	5	4	4	4	4
HDPE	5	5	5	3	2	4
MDPE	5	5	5	3	2	5

1 = Poor 5 = Excellent

Table adapted from Table 3.8.1 from Microhydro Design Manual, a Guide to Small-scale Water Power Schemes, A. Harvey 1993

Ductile iron: These pipes can have an internal coating of cement, affording better corrosion protection and low friction loss. Ductile iron is a heavy material, however, which leads to a difficult and more costly installation. Ductile iron allows for multiple jointing options, including mechanical joints (bolted gland), push-in spigot and socket with a flexible seal, or occasionally flanged.

Figure 42: Ductile Iron Pipe

Photo courtesy of Alibaba.com

Concrete: Several factors come into play with concrete penstocks which make them typically unsuitable for use, even at moderate pressure. Concrete's friction loss characteristics can be highly variable. Further, the material's excessive weight makes transportation and installation difficult. However, steel reinforced concrete pipes, particularly when they are pre-stressed, can serve as a cost-effective alternative for low and medium head sites. Concrete penstocks typically have rubber ring joints.

Figure 43: Concrete Penstock with Spun Rubber Ring Joints

Photo courtesy of Hynds Water

Glass-reinforced plastic (GRP): GRP can be a material option depending on the cost and availability. The pipes are comprised of resin reinforced with spirally wound glass fiber and inert filler such as sand. GRP pipes are suited for high pressure applications and have a low weight and minimal corrosion and friction loss. Typically, joints are spigot and socket with a flexible seal. The pipe is fragile and requires careful installation. To provide the best protection, it is recommended that GRP pipes are buried and backfilled with fine material. Evidence suggests that GRP may be weakened over a long period of time, due to water absorption via osmosis.

Figure 44: GRP Penstock

Photo courtesy of All-Biz

Mild steel: Mild steel is likely the most widely utilized penstock material for small hydro systems. Its low cost and ease of acquisition add to its appeal. Mild steel provides a greater versatility for pipe diameter and thickness. It has moderate friction loss. Mild steel penstocks are resistant to mechanical damage but can be more susceptible to corrosion when the pipelines are buried. While these pipes are heavy, they can easily be manufactured in smaller segments, thus making transportation and installation easier. The jointing on mild steel pipes can be achieved by on-site welding, flanges, or mechanical joints.

Figure 45: Spiral Welded Mild Steel Piping

Photo courtesy of steelpipes.org

Polyvinyl chloride (PVC): PVC is a commonly used penstock material. It has low friction loss and a high resistance to corrosion. PVC is available in a large range of sizes and pressure ratings and the cost is relatively low. Additionally, the material is lightweight, increasing the ease of transportation and installation. However, PVC is relatively fragile and susceptible to mechanical damage from impacts, particularly at low temperatures. Further, PVC will deteriorate when exposed to ultraviolet light; the sun exposure will cause surface cracking, which in turn, will have a significant consequence on the pressure rating of the pipe. As such, the pipe must always have protection from direct sunlight by burying, covering with foliage, wrapping, or painting. PVC also requires continuous support along the length of the penstock due to its high vulnerability to stress fatigue. If the PVC is allowed to bend, there will be an introduction of internal forces against the wall of the pipe; further, vibrations induced by water flow can be enough to cause a stress fatigue failure after only about 5 to 10 years of operation. Because of this, it is recommended that PVC pipe be run along the ground or preferably buried. PVC pipe segments can be joined using spigot and socket with PVC pipe cement or using spigot and socket with a flexible sealing ring.

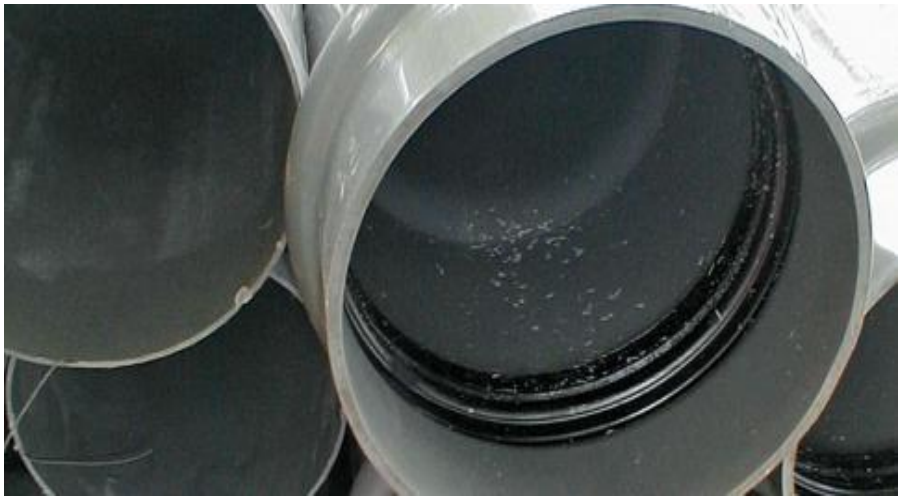


Figure 46: PVC Piping

Photo courtesy of Home Power

High and medium density polyethylene (HDPE and MDPE): HDPE and MDPE pipes have minimal friction losses and are highly resistant to corrosion. The materials provide a good alternative to PVC although material cost is somewhat greater. HDPE and MDPE pipes are available in sizes from less than an inch to over three feet in diameter. Installation is relatively easy, particularly in smaller-scale applications. Jointing is generally achieved by heating the ends of the segments and fusing them together using special equipment. Because this method is more labor-

intensive, installation cost will be higher. For smaller diameter pipes, mechanical compression fitting joints can prove to be a cost-effective alternative to fused joints.

Figure 47: HDPE Penstock

Photo courtesy of KWH Pipe

Step 2D. Turbine Selection

Hydro turbines can be categorized into two groups: impulse turbines and reaction turbines, whose difference relates to the way that energy is produced from the inflows. In a reaction turbine, the water flows over the runner blades and energy production results from the combined forces of the pressure and moving water. The turbine must be encased in a pressurized housing and fully submerged in water. Reaction turbines are generally better suited for lower head, higher flow applications. An impulse turbine uses the force of a jet of water impacting a runner's curved buckets to change the direction of flow and thus creating momentum to produce mechanical energy. An impulse turbine can be open to the air, and only needs a casing to control splash. Impulse turbines are generally well suited for high head, low flow applications. Both runners are shown in Figure 48 and Figure 49.

Figure 48: Reaction Turbine (Kaplan) Runner

Photo courtesy of www.ucmr.com

Figure 49: Impulse Turbine (Pelton) Runner

Photo courtesy of Canyon Hydro

There may be several turbines capable of operating at a given design flow although they will likely differ in efficiency or range. The design flow for smaller systems may also be dictated by standard turbine sizes. The chart below shows seven major types of turbines and their recommended range of head and flow. Preliminary use of this chart will enable the identification of potential turbine types that are suitable for a given design head and flow. For example, if the design head is 100 feet and the design flow is 100 cfs, three turbines may be appropriate for the site: a Francis, a Kaplan or a Cross Flow. Each turbine has certain advantages and disadvantages which may dictate selection. All turbines in the chart are discussed in more detail in the next section.

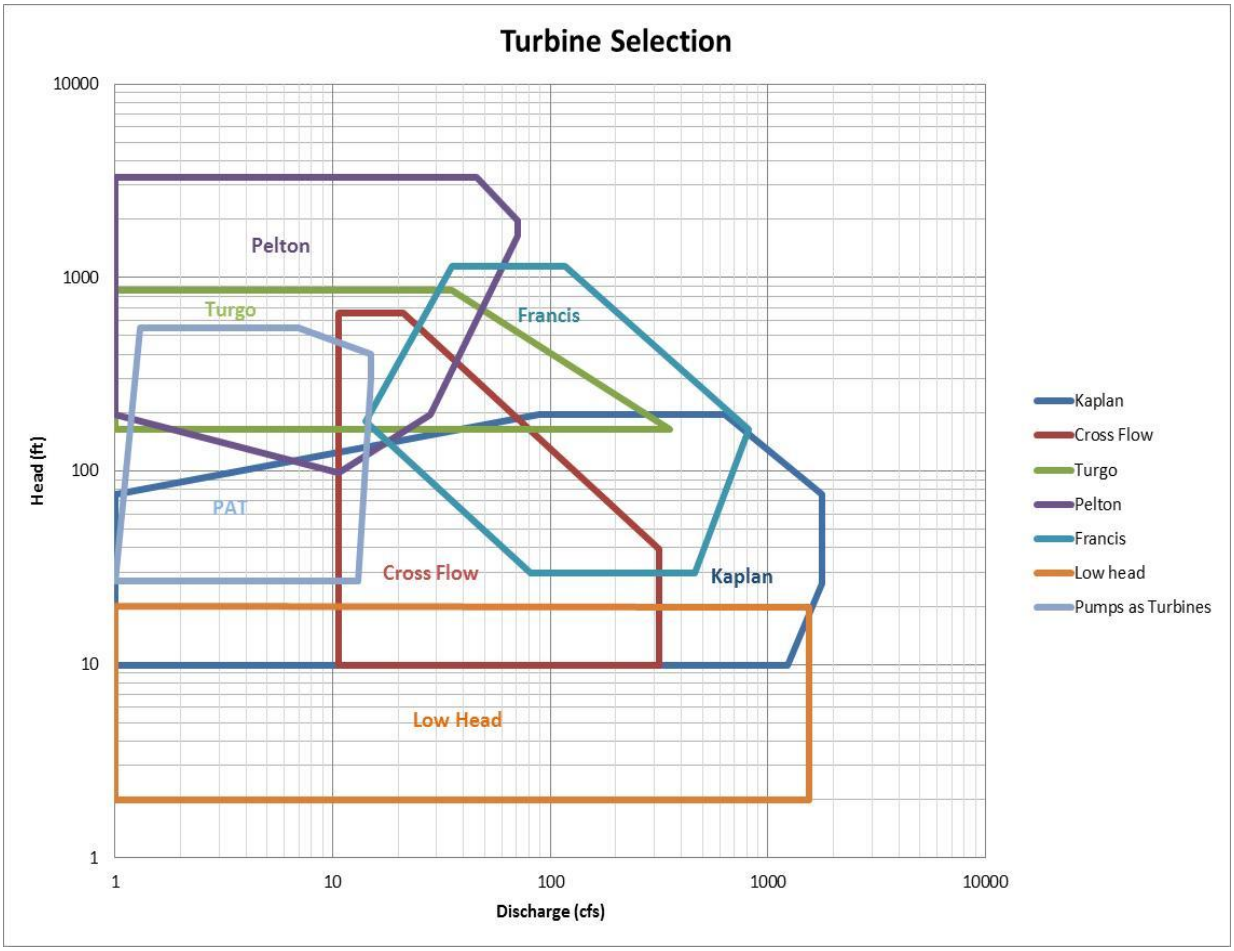


Figure 50: Turbine Selection Chart

Each turbine will have an associated efficiency curve that may be obtained from the turbine manufacturer; the curve depicts the relationship between the flow and efficiency under certain or design head. Use of these diagrams will allow for the analysis of how each turbine will perform under specific conditions. Generally, a flatter efficiency curve represents a turbine

that can operate under broad ranges of head and flow. Curves that are steeper and narrower are indicative of a turbine designed for more focused ranges of operation.

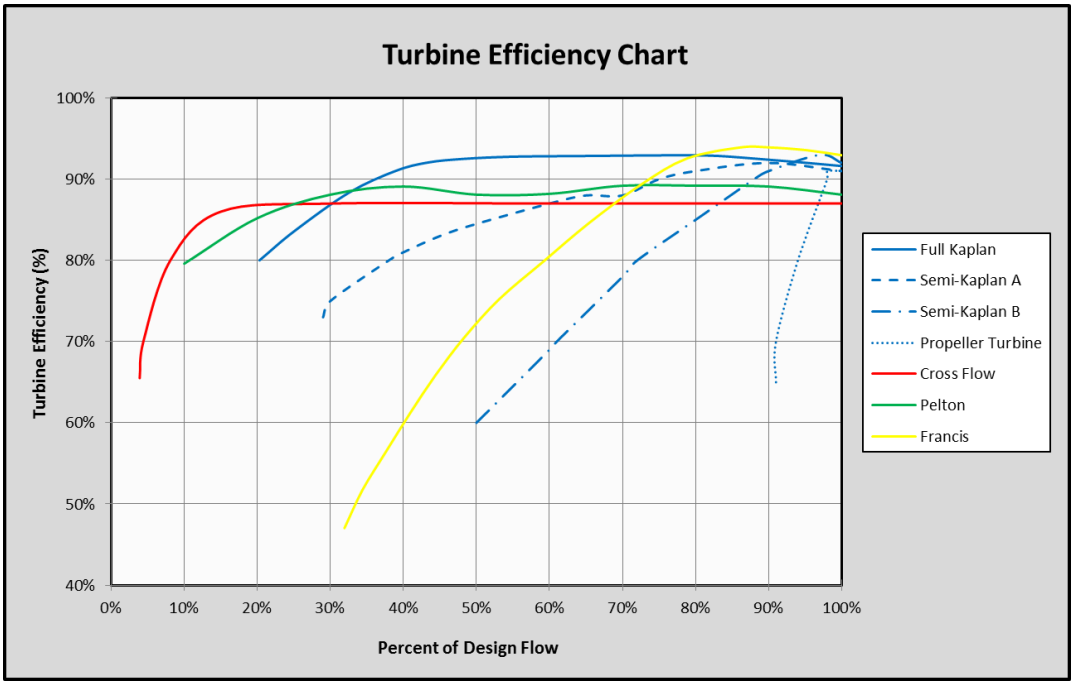


Figure 51: Typical Turbine Efficiency by Type

Generalizing the cost for turbines can be very difficult as they can be designed specifically to accommodate individual site conditions. Appendix 5 contains a list of turbine manufacturers; when contacted directly with the specific conditions of the proposed hydro site, an appropriate quote can be obtained. Generally speaking, turbines that are able to effectively cover a large operating range will be greater in cost. A reduction in the target operating range could equal cost savings, though the hydro system will be less able to accommodate variable flow.

2D1. Turbine Types

Kaplan Turbine (Figure 52): The Kaplan Turbine is highly adjustable, in both the pitch of the runner blades as well as the inlet guide vanes. This adjustability increases efficiency and allows for a larger flow operating range; Figure 53 shows the varied positions of the rotor blades to accommodate changing flows. A Kaplan is ideal for low head sites, ranging in net head from about 10 feet to 65 feet. Optimally, the turbine will have large flows through the turbine; the peak discharge for which the Kaplan operates ranges from approximately 100 cfs to 1050 cfs.

The turbine works by utilizing flow through the inlet guide vanes that acts upon the propeller-like blades to create shaft power. While the Kaplan is relatively expensive compared to other types of turbines, its adjustability, and thus, higher efficiency adds to its appeal. Further, different versions of the Kaplan are available for varying conditions, which can reduce the price

of the turbine. The full version of a Kaplan Turbine has both adjustable inlet guide vanes as well as adjustable pitch on runner blades. There are also two versions of "semi-Kaplan" turbines: one version has only adjustable runner blades and the other version has only adjustable inlet guide vanes. Both of these are shown in Figure 53. A propeller turbine is basically a Kaplan with both fixed runner blades and inlet guide vanes. As evident from the Efficiency Curve, a propeller turbine is optimized for a very specific operating range. The Semi-Kaplan and propeller turbines will have a lower cost than a Full Kaplan, however their operating efficiencies are reduced by varying degrees.

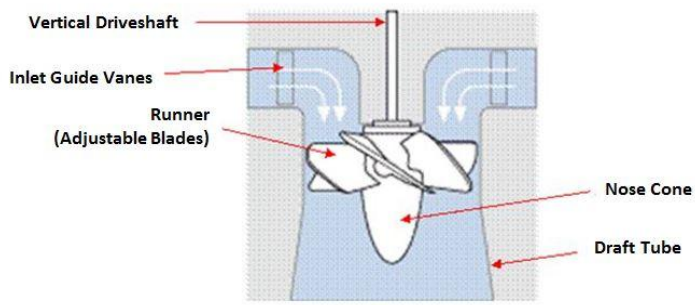


Figure 52: Kaplan Turbine Schematic

Photo courtesy of Renewables First

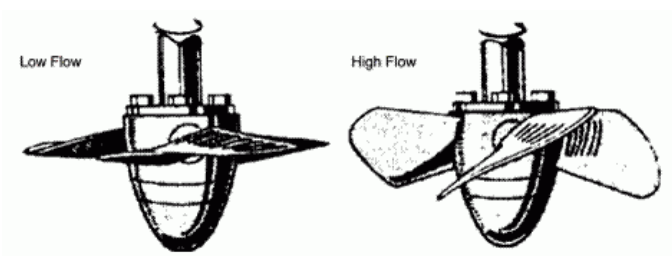


Figure 53: Kaplan Runner Blade, Varied Pitch

Photo courtesy of Renewables First

Cross Flow Turbine (Figure 54 and Figure 55): The Cross Flow Turbine is named for the way the water flows across the runner. Because most Cross Flows have two or more inlet guide vanes, this type of turbine can maintain a high efficiency over a wide range of flow rates. By altering the operation of the inlet guide vanes to better suit flow conditions, flow can be directed at just a portion of the runner during low inflow, or the entire runner when higher flows dictate. As evident from the efficiency curve, the Cross Flow is able to maintain a consistent efficiency.

The Cross Flow has a large operating range of net head, spanning from approximately 5.5 feet to 650 feet, although it will become less cost effective for heads greater than 130 feet. The Cross Flow can maintain a higher percentage of efficiency over a broad range of flow, on as little as 1.5 cfs, up to 175 cfs, making it well-suited for seasonally fluctuating flow sources. The

Cross Flow's major advantage is that one turbine can operate over a large range of flow. Further, due to its self-cleaning design and standardized componentry, the turbine requires very little maintenance and should operate efficiently for at least 40 years.

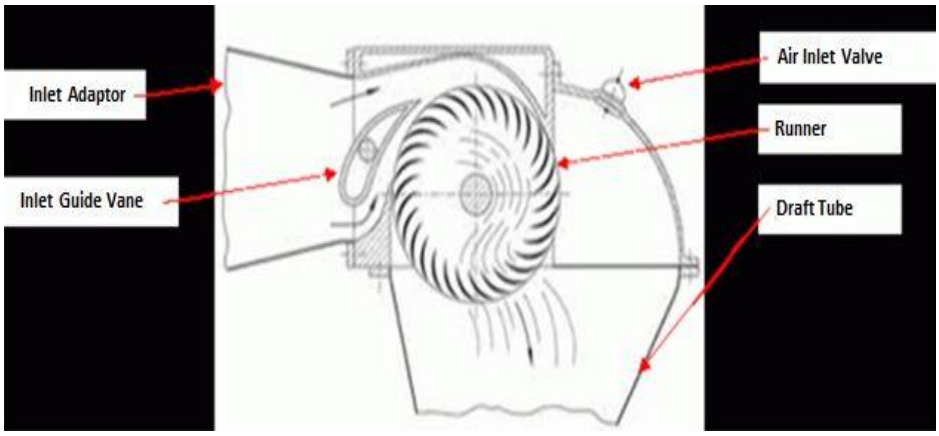


Figure 54: Cross-section of Cross Flow Turbine

Photo courtesy of Renewables First

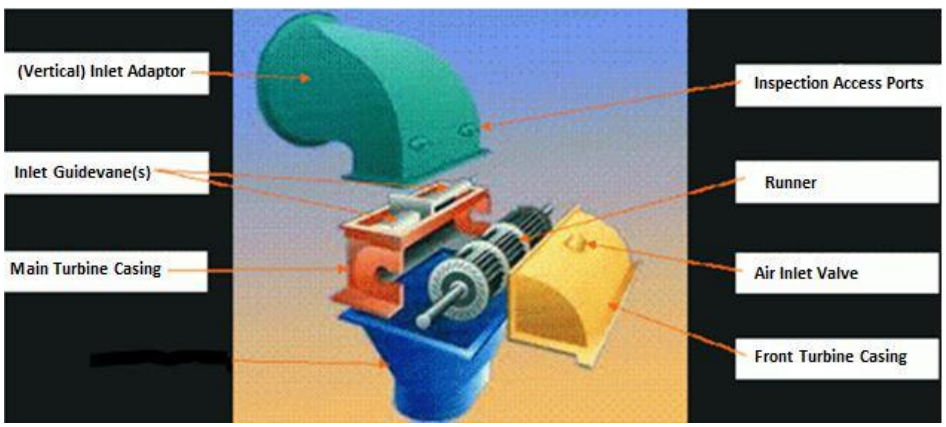


Figure 55: Cross Flow Exploded Schematic

Photo courtesy of Renewables First

Pelton Turbine (Figure 56 and Figure 57): The Pelton Turbine has a high operating head. Because the operating head is so high, the flow rate tends to be low, amounting to as little as 0.2 cfs. The turbine requires the flow through the inlet to be highly pressurized, making proper penstock design crucial. The Pelton utilizes a nozzle located in the spear jet, which is used to focus the flow into the buckets on the runner. The spear jet and buckets are designed to create minimal loss; this leads to a potential efficiency of 90%, even in small hydro applications. A Pelton Turbine can have up to six spear jets (shown in Figure), which effectively increase the flow rate to the turbine resulting in a greater power production and efficiency. The efficiency curve depicted in Figure depicts an efficiency curve for Peltons having a twin-spear jet.

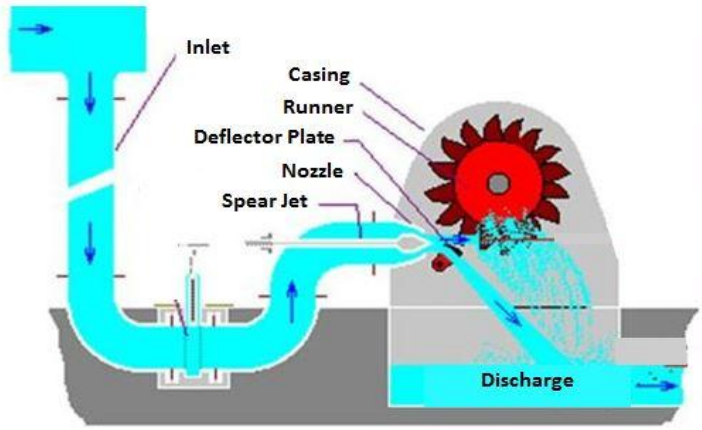


Figure 56: Pelton Turbine Schematic

Figure courtesy of PumpFundamentals.com

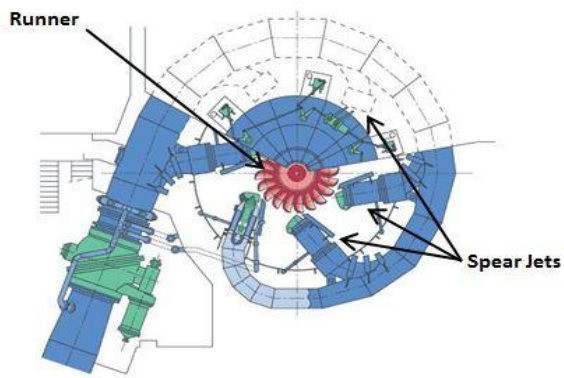


Figure 57: Cross-section of Pelton Turbine

Figure courtesy of Voith Hydro Power

Turgo Turbine (Figure 58): The Turgo Turbine was developed from the Pelton Turbine and utilizes much of the same technology. Turgo turbines are typically utilized for lower heads and higher flow rates than Pelton turbines. Turgo efficiency is less than that of the Pelton but the Turgo retains the ability to support a broad flow range. The main physical differences between the two relate to the flow path of water through the turbines and the cup shape on the runners.

Figure 58: Turgo Runner

Photo courtesy of PowerPal

Francis Turbine (Figure 59 and Figure 60):
The Francis Turbine is the traditional turbine for standard, medium head. It has a reliable, simple construction, with adjustable guide vanes and fixed runner blades. From the efficiency curve, it can be seen that the Francis has a narrow operating range for peak efficiency.

Figure 59: Francis Runner

Photo courtesy of Oak Ridge National Laboratory; Best Practice Catalog, Francis Turbine

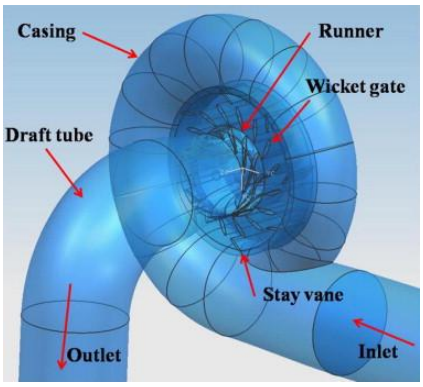


Figure 60: Francis Turbine

Photo courtesy of ScienceDirect

Low Head Turbine (Figure 61): The use of Low Head Turbines is an emerging market. While the previously described turbines are generally bought as custom units, Low Head Turbines have been standardized in an attempt to keep associated costs low. Companies that manufacture Low Head Turbines are continually attempting to design low cost, standard turbines for particular situations and markets. There are multiple types of low head turbines. For very low head sites, a Low Head Turbine system may be a suitable and economical alternative to a traditional turbine system. Figure 61 shows an installation comprised of multiple Low Head Turbines. Applegate Group and Colorado State University published a Low Head Hydropower Study in which a more detailed list and description of available low head turbines can be found.

Figure 61: Multiple Low Head Turbines System

Photo courtesy of Mavel

Pump as Turbine (Figure 62): Centrifugal pumps can function as turbines by running flow through them in reverse. Their use is optimal in conditions in which a fixed flow rate is consistently available throughout the year. Because pumps are mass-produced, this alternative can be an appealing option. PATs are available in a multitude of standard sizes and in a large operational range of head and flow. Replacement parts are more readily accessible and affordable and will typically have a faster turn-around time for delivery. The PAT system offers a simple design as well. In most cases, it is more reasonable to have a direct drive, in which the pump shaft is connected directly to the generator, rather than fitting the system with a belt drive. This absence of a belt drive adds further benefit to the PAT system: reduction in friction loss, longer bearing life, less maintenance, and a lower cost. Furthermore, the ease of installation increases without the presence of a belt drive as the PAT and generator are designed as a single unit. The main disadvantage to having a direct drive system is that the PAT and generator must run at equivalent speeds, thereby reducing the operational range of flow. When engineered correctly, a pump used as a turbine can prove very cost effective and efficient, particularly when multiple pumps are used in a system to maximize efficiencies.

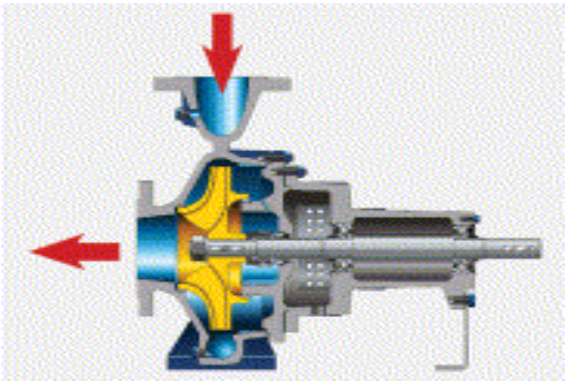


Figure 62: Pump as Turbine

Photo courtesy of World Pumps

See Appendix 5 for a complete list of turbine manufacturers in all sizes.

Step 2E. Powerhouse

The size of the powerhouse is dictated by the equipment configuration, type and quantity of turbines and the landscape of the site. The necessary equipment needs to be configured in an efficient manner with adequate clearance for installation and maintenance. Turbine manufacturers can give recommendations about powerhouse size requirements as well as clearances and offsets between equipment.

Since hydro turbine and generator equipment has substantial weight, it is imperative that the powerhouse foundation be designed to adequately handle the loads to which it will be subjected. The turbine's discharge channel (tailrace) is commonly integrated into the foundation and requires placement consideration when designing the powerhouse foundation. Further, any access to the structure must be large enough to accommodate the placement of

the equipment it will house. A permanent crane may also be necessary to lift and position the equipment within the powerhouse. As such, structural components will need to be designed to withstand the large forces that heavy equipment will transfer to the powerhouse structure.

There are multiple variations for powerhouse configurations based upon the demands of the specific hydro system. For example, Figure 63 depicts a reaction turbine powerhouse. Water is discharged through a tailrace that is incorporated directly into the powerhouse foundation. However, for an impulse turbine powerhouse shown in Figure 64, the tailwater is discharged directly into an open-air excavation rather than via a tailrace. Particular turbine requirements and specifications will need consideration when designing the powerhouse.

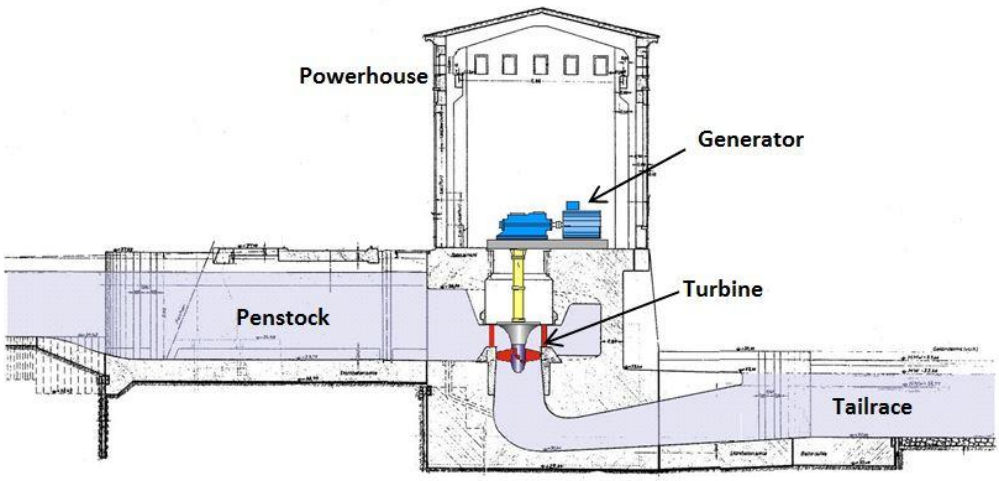


Figure 63: Low Head Powerhouse Schematic

Figure courtesy of "Guide on How to Develop a Small Hydropower Plant" ESHA 2004

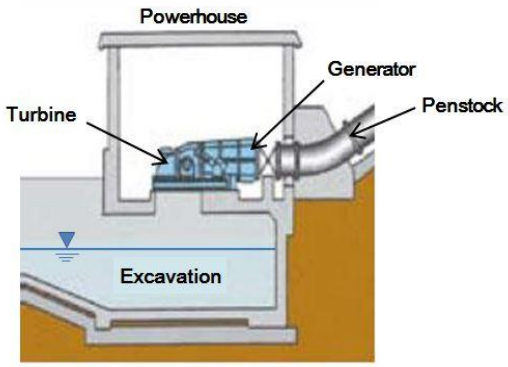


Figure 64: Impulse Turbine Powerhouse Schematic

Figure courtesy of "Guide on How to Develop a Small Hydropower Plant" ESHA 2004

2E1. Intake Structures

Intake Structures are needed for Run-of-the-River projects and Conduit projects to direct the appropriate flow into the penstock and provide for adequate screening. There are several general configurations that can be used in a natural stream or a canal; a lateral, side or bottom intake. These three basic configurations are shown in the figures below.

The higher the head on the turbine, the more important is to have water free from sediment. Of the three intake configurations shown below, the side intake is desirable because most of the debris and bed loads can completely bypass the screens. The first two configurations, the lateral and side intake, require the watercourse to be checked up or dammed to an elevation that will result in an overflow onto the screens. This can be accomplished with a permanent or movable structure, with permanent structures ranging from rock dams and dikes to concrete structures. All diversion dams or other structures should include a gate to sluice the sediments that will accumulate behind the dam. Adding a movable gate to the diversion structure allows for more control of both the intake and bypass flow. Several types of movable gates and checks are listed by manufacturer below in Appendix 6.1

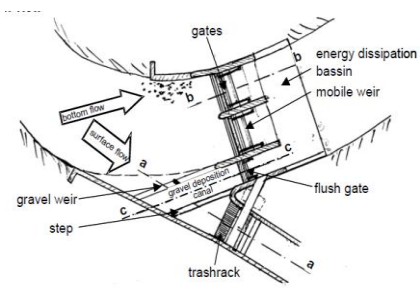


Figure 65: Lateral Intake

Photo courtesy of "Guide on How to Develop a Small Hydropower Plant" ESHA 2004

Figure 66: Side Intake

Photo courtesy of HydroScreen, LLC

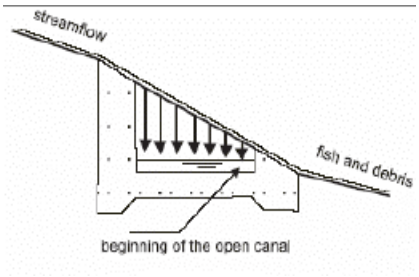


Figure 67: Bottom Intake

Photo courtesy of "Guide on How to Develop a Small Hydropower Plant" ESHA 2004

a) <u>Screening</u>

Common to all intake structures is sediment and trash control. Screening the water before it enters the turbine will prevent accelerated wear of runners and other components of the turbine. Floating debris may also cause significant damage if allowed to enter the turbine. Screen selection will depend on the type of debris and sediment expected. Several screen types are shown below with general characteristics of each type.

Table 3: Comparison of Several Screening Options

Screen type	Screen Size	Electricity	Turbine Type	Flow	Head Loss
Wedge Wire	Very fine	No	All	Medium	High
Bar Trashrack and Rake	Coarse	Yes	Low head	High	Low
Drum Screens	Very fine	Some	All	Low	High
Motorized Screens	Medium	Yes	Low Head	Medium	Medium

When choosing a screening method, considerations should include accessibility for maintenance, access to service power, size of the debris and sediments and the selection of the turbine. The head loss that occurs through the screen should also be considered. A list of manufactures of screens, trashracks, cleaners and other intake devices can be found in Appendix 6.2

b) Submergence

Submergence of the penstock inlet is a design consideration for the intake structure. The inlet of the penstock must be sufficiently submerged under water such that air is not drawn into the penstock or vortexes created on the water surface. To prevent this from occurring, a general rule of thumb is to submerge the penstock inlet a full penstock diameter below the water surface. This depth may be reduced through a hydraulic analysis of the structure.

c) Discharge Structure

The Tailrace, or discharge structure, is located downstream of the turbine and takes the water discharged from the turbine back to the watercourse. The discharge structure design will depend on the type of turbine and the turbine configuration. The typical powerhouse layouts shown above show that the discharge structure may be integral to the building foundation. This will save on civil construction costs and space.

Reaction turbines (Kaplan, Propeller, or Francis) will require a draft tube and tailwater to function properly. These turbines take advantage of the suction provided by the draft tube downstream of the turbine. A draft tube is simply the outlet pipe downstream of the turbine. The draft tube must be submerged in water, which is achieved by maintaining tailwater with the concrete structure, or setting the bottom of the draft tube below the downstream water surface. Several examples of draft tubes and discharge structures are shown in Figure 67.

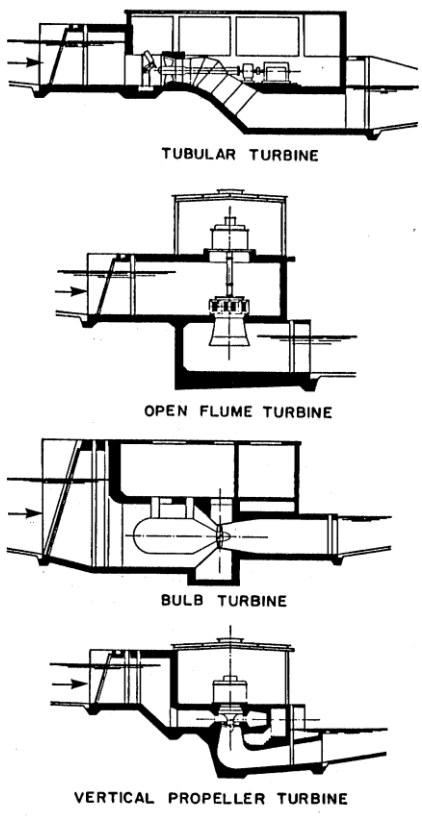


Figure 68: Discharge Examples

Photo courtesy of Gulliver and Arndt, 1991

Alternatively, impulse turbines (Pelton, Turgo and Crossflow) do not take advantage of head downstream of the turbine. These turbines will discharge into the open air and do not require a set tailwater elevation or a draft tube.

Step 2F. Controls

Small hydro turbine/generators are commonly sold as "water-to-wire" packages. The manufacturer/distributor will supply all of the equipment, turbine, generator, controls, and switchgear according to specifications and interconnection requirements.

Grid Interconnection Controls

Grid interconnection controls, including automatic controls and switchgear, will synchronize generation with the frequency and voltage of the grid. It will also safeguard both equipment and the grid in the case of failure. The system will monitor the grid frequency and voltage and automatically adjust generation to match. This is a fundamental interconnection requirement for all utilities. Additional capabilities may be included in customized controls including water level monitoring and operation of flow control valves. Please see Appendix 7 for a list of controls manufacturers that can provide additional information.

Emergency Shutdown System

The ability of the system to disconnect automatically is also a fundamental interconnection requirement. The turbine and generator need to stop operating if the grid fails. The generator cannot be feeding power into the grid in this case for the safety of line workers and the general public. The controls will detect the loss of power and automatically disconnect the generator. This creates a problem where the generator is no longer experiencing a load and it will tend to increase in speed if the turbine is still passing water and turning the generator. Ultimately, if the turbine is allowed to spin at "runaway speed", there is the potential that it will spin so fast, water will not be able to pass through the turbine. This could cause a catastrophic pressure surge in the pipeline. It will also cause damage to the generator if it is allowed to spin freely.

There are several safeguards that can be included in the system depending on the turbine type. In general, the safeguard is a method to remove water from entering the turbine and spinning the runner. For impulse turbines, a deflector may be used that simply deflects water from the runner in the case of an emergency shutdown. Water will still be traveling through the penstock, but just discharging directly without turning the runner. Reaction turbines need to be shut down slowly and water flow stopped through the penstock or directed away from the penstock. This type of control is generally achieved through automatic valves or gates that close slowly to prevent a pressure surge.

Off the grid applications

Without the grid to regulate the frequency and voltage of the generator, a load governor is needed. A governor or load management system can distribute generation to loads according to preset priorities and includes one load to shed excess generation. Loads to shed excess generation may include battery charging, space, water or ground heaters. A governor is necessary to balance varying loads and generation that do not have the benefit of the grid.

Step 2G. Electrical Interconnection and the State Electrical Board

The cost and complexity of electrical interconnection depends upon the scale of the project and type of interconnection required.

For a smaller project, a simple net metering agreement and interconnection agreement can usually be arranged with the local utility without difficulty. Under current Colorado law, most CO utilities are obliged to provide net metering for residential systems up to 10 kW and commercial systems up to 25 kW (larger limits apply to Colorado's two investor-owned utilities).

For larger hydro systems, the local utility may require an interconnection study to determine whether or not the project would cause any adverse impacts on utility infrastructure or

operations. The interconnection study might be completed by the utility itself or by an engineering firm approved by the utility, although in both cases costs of the interconnection study will typically be paid for by the project developer.

Project interconnection approval will also require approval by a state electrical inspector, with the applicable inspection guidelines varying depending upon whether or the project is net metered. For a net metered system, inspection guidelines require that all electrical equipment be U.L. listed and be installed and used in a manner consistent with the specified use on the equipment nameplate. This can present difficulties for small hydropower systems, where it is common to use small motors as generators and custom controls systems that have not been tested at a laboratory. Unfortunately, however, this can create inspection approval problems.

The simplest way to avoid this problem is to purchase a motor which is labeled as a generator. If needed, it is possible to petition the Colorado State Electrical Board requesting issuance of a formal waiver, providing formal permission for use of a motor as generator.

Step 2H. Buyer for Energy and Renewable Energy Credits

When completing a project feasibility assessment, it is necessary to estimate the expected value of both the energy and the RECs that will be generated by the system.

Renewable Energy Credits

A Renewable Energy Credit (REC) represents a claim to the environmental attributes associated with renewable energy generation. RECs are tradable instruments that can be used to meet voluntary renewable energy targets as well as to meet compliance requirements for renewable portfolio standards. A REC is a certificate that represents the generation of one megawatt-hour (MWh) of electricity from an eligible source of renewable energy. Each REC denotes the underlying generation energy source, location of the generation, and year of generation (a.k.a. “vintage”), environmental emissions, and other characteristics associated with the generator. Unlike electricity, RECs do not need to be scheduled on a transmission system and they can be used at a different time than the moment of generation. Certificate tracking systems have been established to issue and record the exchange of RECs. REC prices vary according to market trends in both the voluntary and compliance market.

Colorado has a Renewable Portfolio Standard (RPS) requirement which helps to drive Colorado REC pricing. Colorado's RPS requires electric utilities to provide specific percentages of renewable energy by certain dates, helping to support development of new renewable energy in Colorado, including hydropower.

Energy

The most logical potential energy purchaser for a given project is usually the local utility. Colorado's electric utilities are comprised of investor owned utilities, rural electric cooperatives and municipal utilities.[vi] Energy is typically sold in kilowatt-hour or megawatt-hour increments through a power purchase agreement (PPA). A Power Purchase Agreement (PPA) is a contract between two parties, one who generates electricity and one who purchases the electricity. The PPA typically defines all of the commercial terms for the sale of electricity between the two parties, including delivery of electricity, penalties for under-delivery, payment terms and termination. For a sample PPA, see Appendixes.

Many Colorado rural cooperatives purchase their energy wholesale from Tri-State Generation and Transmission (Tri-State). Tri-State's Local Renewable Program (Policy 115) enables Tri-State member cooperatives to purchase the output from local renewable resources, including hydropower, in an amount up to 5% of annual energy sales. The cooperative determines whether a particular local renewable project qualifies under Tri-State Policy 115. The energy payment amount under Tri-State Policy 115 is determined through a regularly-updated payment schedule established by Tri-State.

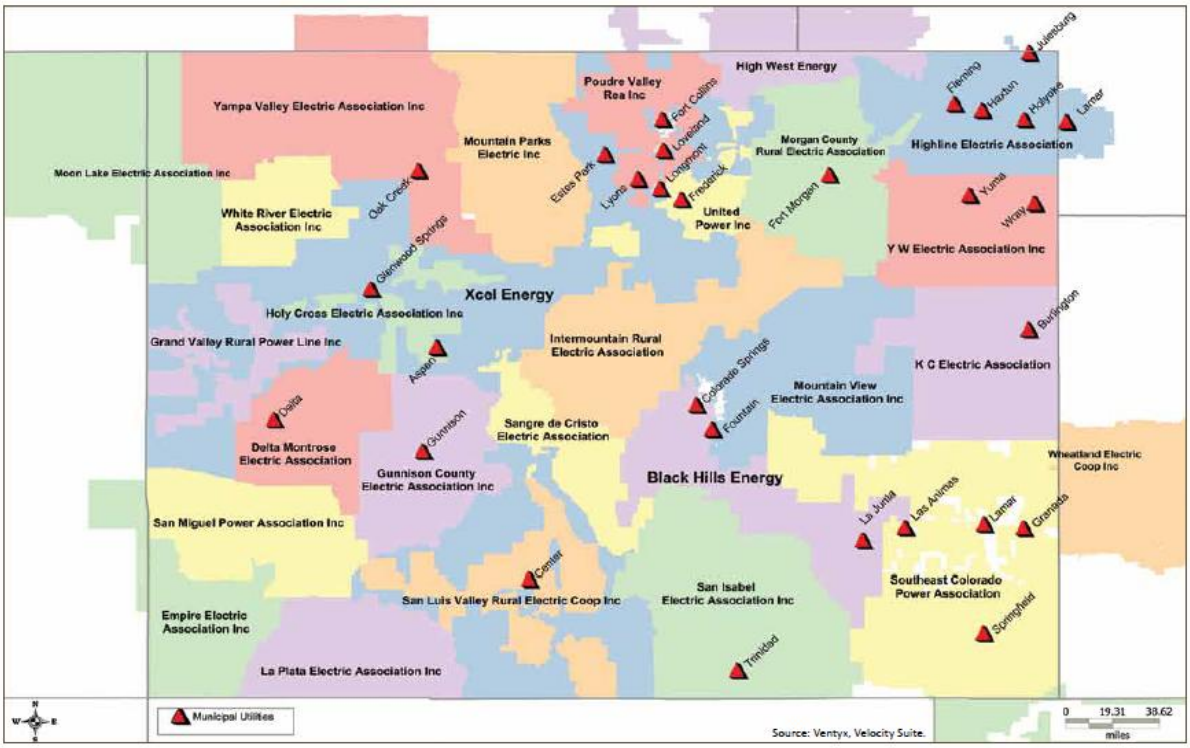


Figure 69: Colorado's Electric Utility Service Territories

Source: Colorado Governor's Energy Office. 2010 Colorado Utilities Report. August 2010, p iv.

Net Metering

Net metering is an electricity sales arrangement for consumers who develop small renewable energy facilities. Under a net metering agreement, generated electricity is used directly by an adjacent facility. Meters record electricity usage in both directions, meaning electricity can either be consumed from the grid or the excess generated electricity can be exported back onto the grid. In many cases, a generating facility might not use all the locally-generated electricity, resulting in a credit from the utility.

For projects located in the service territory of Colorado's two investor-owned utilities, net metering projects must not exceed 120% of the customer's average annual consumption. For projects located within municipal utilities and rural cooperatives, customer-sited generation cannot exceed 10 kW for residential projects and 25 kW for non-residential projects.[vii]

When considering net metering, you will need to know the local utility's policy on net metering and how the excess generation will be sold. It is also important to know how far it is from the adjacent load to the generating facility. You will also need to determine whether the annual electric load of the adjacent facility matches that of the proposed generating facility.

Step 2J. Permitting: Types and Timelines

Hydropower projects typically require a license or exemption from the Federal Energy Regulatory Commission (FERC) or the Bureau of Reclamation (see Step 3). In addition to these requirements, construction activities in a river or stream can trigger additional local, state and Corps of Engineers permitting.

Corps of Engineers, Clean Water Act, Section 404

The Army Corps of Engineers regulates all construction activities occurring in "Waters of the US" by authority of the Clean Water Act, Section 404. Construction activities include the removal or deposition of material from below the ordinary high water mark. This can include any natural waterway or wetland. There are basically three levels of Army Corps involvement in a hydropower project: 1) If the project is located on a canal or pipeline, the Army Corps may have no involvement; 2) If the construction activity is minor and/or the project qualifies for a FERC exemption, the project may qualify for a Nationwide Permit, discussed more below; or 3) If the amount of disturbance or quantity of dredge or fill is more than what qualifies for a Nationwide Permit, an Individual Permit is required.

No Army Corps involvement

If the project is located entirely on a manmade waterway or a conduit, the Army Corps may not have jurisdiction over the project. This is explained in more detail in a guidance document provided by the Army Corps: Regulatory Guidance Letter No 07-02: SUBJECT: Exemptions for

Construction or Maintenance of Irrigation Ditches and Maintenance of Drainage Ditches Under Section 404 of Clean Water Act

Nationwide permits

Nationwide permits are designed for specific activities that will have little impact on water or environmental quality. These permits are subject to fewer requirements than an individual permit and are meant to expedite the permitting process. There are several Nationwide permits that could apply to hydropower construction activities:

i. Nationwide permit #17 for Hydropower

For discharges of dredged or fill material associated with hydropower projects having: (a) Less than 5000 kW of total generating capacity at existing reservoirs, where the project, including the fill, is licensed by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act of 1920, as amended; or (b) a licensing exemption granted by the FERC pursuant to Section 408 of the Energy Security Act of 1980 (16 U.S.C. 2705 and 2708) and Section 30 of the Federal Power Act, as amended. (Section 404)

ii. Nationwide permit #18 for minor discharges

For minor discharges of dredged or fill material into all waters of the United States, provided the activity meets all of the following criteria: (a) The quantity of discharged material and the volume of area excavated do not exceed 25 cubic yards below the plane of the ordinary high water mark or the high tide line; (b) The discharge will not cause the loss of more than 1⁄10-acre of waters of the United States; and (c) The discharge is not placed for the purpose of a stream diversion. (Sections 10 and 404)

iii. Nationwide Permit #19 for minor dredging

For dredging of no more than 25 cubic yards below the plane of the ordinary high water mark or the mean high water mark from navigable waters of the United States (i.e., section 10 waters). This NWP does not authorize the dredging or degradation through siltation of coral reefs, sites that support submerged aquatic vegetation (including sites where submerged aquatic vegetation is documented to exist but may not be present in a given year), anadromous fish spawning areas, or wetlands, or the connection of canals or other artificial waterways to navigable waters of the United States (see 33 CFR 322.5(g)). (Sections 10 and 404)

Individual Permit

If a project does not fit into the requirements of one of the nationwide permits, an individual permit must be obtained. These permits will take more time to obtain and have more requirements than a Nationwide permit. To ensure adequate compliance with the Clean Water Act, the local USACE office should be contacted and consulted regarding specific projects. A map and list of contact information is included in the external references, entitled "USACE Colorado Offices".

State Department of Environmental Quality, Section 401

The Colorado Department of Public Health and the Environment, Water Quality Control Division issues water quality certifications for facilities which may result in any fill or discharge into the navigable waters of the United States. These certifications are required if a federal permit is issued for the facility, such as a FERC exemption or license. Additional guidance for these certifications is included in the external references, entitled "State of Colorado Water Quality Certification fulfilling the requirements of Clean Water Act Section 401".

1041 Regulations

In 1974, the Colorado General Assembly enacted measures to further define the authority of state and local governments in making planning decisions for matters of statewide interest. These powers are commonly referred to as "1041 powers", based on the number of the bill of the proposed legislation (HB 74-1041). These 1041 powers allow local governments to identify, designate, and regulate areas and activities of state interest through a local permitting process. The general intention of these powers is to allow for local governments to maintain their control over particular development projects even where the development project has statewide impacts. The statute concerning areas and activities of state interest can be found in Section 24-65.1-101.

1041 regulations may apply to a hydropower project if it is considered an activity of state interest which include the following: site selection and construction of major facilities of a public utility; efficient utilization of municipal and industrial water projects; or site selection and construction of major new domestic water and sewage treatment systems and major extension of existing domestic water and sewage treatment systems, among others. In general, a hydropower project on its own would not be considered an activity of state interest, but if the hydropower project is the part of a larger utility scale project, 1041 regulations may apply. Not all local governments have adopted 1041 regulations; each county would need to be contacted to see if these regulations would apply to a specific site. For a full list of permitting resources, please see Appendixes.

Other Federal Permits

For projects located on federal land there, may be specific permitting requirements of the federal agency such as the Bureau of Land Management (BLM), U.S. Forest Service, Bureau of Reclamation, or U.S. Fish and Wildlife.

Local Governments & Neighbors

As explained above, most small hydropower projects will need to submit some sort of federal permit application, either through FERC or through the Bureau of Reclamation. In addition, however, there may be local permits required including through county and town governments. Be sure to check the local zoning laws early on to ensure hydropower is an acceptable land use for the project site.

A project's neighboring citizens can potentially play a large role in the project's development. It is important to engage potentially-affected neighbors early on in the development process. If sound is a concern for a neighbor, local government can create a local noise ordinance which specifies a certain decibel level that cannot be exceeded. If powerhouse aesthetics are an issue of concern, a powerhouse can be designed to match nearby buildings or potentially even placed underground if necessary to minimize aesthetics concerns.

Step 2K. Construction Costs and Cost Categories

The Electric Power Research Institute (EPRI) has issued a report used in the development of a general estimate for costs incurred when creating a small hydro site. See EPRI's report, *Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements*. While the items outlined below may not be all-inclusive, they encompass the majority of expected project tasks. There can be significant variations in cost, depending upon materials used, scale of the system, type of turbine, geological conditions, etc. For a list of construction cost resources and Colorado construction companies, see Appendixes.

Table 4: Typical Small Hydro Costs

Typical Micro Hydro Site	
Typical Equipment Alternative: TBD	
Typical installed capacity: TBD kW	
Preparation of Final E/M Design	$
Permitting/Mitigation	$
FERC Small Conduit License Exemption	$
FERC Qualifying Facility Self Certification	$
Interconnection Application	$
Other Permits and Miscellaneous Fees	$
Legal Fees	$
Acquisition of Access and Rights of Way	$
Cost of Project Components	
Power Transmission	
Interconnection Costs	$
Service Transformer	$
Secondary Service, Disconnect and Metering	$
Hydropower Plant	
Turbine Generator & Controls Supply	$ See Comment 1
T/G Installation and Other E/M Modifications	$ See Comment 2
SCADA Input	$ See Comment 3
Structural and Site Work Allocation	$ See Comment 4
Mobilization and Demobilization	$
Temporary Facilities and Equipment Rental	$
Miscellaneous	$
Subtotal Project Components	$
Field & Technical Support @ 10% of Above Subtotal	$
Profit, Insurance, Bonds, etc. @ 15% of Above Subtotal	$
Subtotal	$
Contingency @ 20% of Above Subtotal	
Total Construction Costs	$
Total Project Costs	$
Total Cost Per kW	$ See Comment 5

Table created with guidance from EPRI (Electric Power Research Institute, 2011)

Comment 1: The supply costs for the turbine, generator, and controls can range from $1,000/kW to $2,000/kW depending on the unit type, operating head/flow range, and required protections.

Comment 2: Equipment installation can range approximately 50% (+/-) of the equipment supply costs.

Comment 3: SCADA input can range approximately $10,000 to $15,000.

Comment 4: As a rule of thumb, the civil works costs should be less than or equal to the equipment costs.

Comment 5: The total project costs can range approximately $2,000/kW to $8,000/kW depending on specific site characteristics and impacts to existing infrastructure.

Step 2M. Federal and State Incentives

Hydro projects greater than 150kW are eligible for the following federal tax incentives (projects can choose one or the other): 1) the Investment Tax Credit (ITC), which can be claimed in year one of a project for 30% of depreciable capital costs; the ITC also reduces the project's depreciable basis by 15%; 2) The Production Tax Credit (PTC), which is worth $11/MWh for the first ten years of the project's operations (with the PTC value escalating slightly with inflation). Only private sector entities are able to take advantage of these tax credit incentives.

As part of the legislative package passed at the beginning of January 2013 to avert the "fiscal cliff," Congress enacted some important extensions for these renewable energy tax incentives. The Production Tax Credit was extended and modified for qualified hydropower facilities, stating that the Production Tax Credit can still be utilized if *construction begins* before January 1, 2014. The bill also included an extension of 50% bonus depreciation for projects placed in service before January 1, 2014.

Typically, only companies with significant tax liabilities can benefit from these federal tax incentives, which in practice has meant that renewable energy project developers must enter into complicated financial arrangements with outside investors to make use of the federal tax incentives: outside investors provide capital for the project and in return benefit from the tax incentives.

Step 2N. Economic Modeling: Cost Benefit Analysis

A feasibility study will typically include economic modeling for a range of possible construction cost and energy sales price scenarios, estimating the expected costs and benefits of each scenario. Most projects will need to take out a loan to pay for construction costs. Annual loan payments will depend on the amount of the loan and the interest rate. Operations and Maintenance should also be included in the economic model and may be estimated at around 10% of the project's total annual revenue. These costs include mechanical maintenance, repairs, inspections, labor, etc. The economic model may also need to include transmission and wheeling costs. "Wheeling" refers to the transfer of electrical power through transmission and distribution lines from one utility's service area to another's. Finally, it is typical to include a capital reserve line item in economic modeling to generate a pool of funds which can be used to pay for periodic major repairs and equipment replacement.

RETSCREEN is a commonly-used economic model. It is an Excel-based project analysis software tool that helps to determine the economic feasibility of a potential project.

STEP 3 Permitting, Finance and Interconnection

3A1. **Pending Legislatives Changes to Federal Permitting Requirements for Small Hydro**

Federal Legislation

There are various legislative reform efforts currently underway which could dramatically simplify federal permitting for small hydro development.

H.R. 267, the *Hydropower Regulatory Efficiency Act* was introduced in January 2013 by U.S. Rep. Diana DeGette (D-CO) and U.S. Rep. Cathy McMorris Rodgers (R-WA). The bill will allow FERC to exempt hydropower projects with up to 10 megawatts of capacity (instead of the current 5 MW cap) from licensing requirements and removes any project below 5 MW from FERC licensing oversight. The bill also authorizes FERC to waive licensing requirements for "conduit" hydropower facilities — defined as any manmade water conveyances operated for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity — with an installed maximum of 40 MW or less.

H.R. 678, the *Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act*, was introduced by Rep. Scott Tipton (R-CO), which would, among other provisions, simplify application of the National Environmental Policy Act (NEPA) to conduit hydropower projects on Reclamation facilities with capacity of 5 MW or less.

These two bills together cut red tape and broaden eligibility criteria for low-impact hydroelectric development at non-federal and federal facilities. They were passed through unanimous consent by the U.S. Senate, and signed by President Obama on 8/16/2013

The subsequent sections cover the existing permitting process and still apply until this legislation becomes law.

3A2. **Identifying the Proper Federal Permitting Processes**

The Federal Energy Regulatory Commission (FERC) is the primary federal authority for permitting hydropower projects.[viii] Projects with generating capacity of 5 MW or less or projects utilizing existing conduits may seek FERC authorization for an exemption from FERC licensing requirements.

FERC has detailed information available on their website regarding FERC permitting requirements, including useful templates for developing an exemption or license application. At the beginning of the process, applicants should call FERC to clarify what requirements will apply to a given project site, to receive guidance on working with stakeholders, and to discuss the possibility of requesting waivers for low impact projects.

Projects eligible for an exemption must go through an application process similar to that of a FERC license applicant. Exemptions are issued in perpetuity, unlike FERC licenses, which are typically issued with a 30 to 50 year term and subject to renewal.

If applying for a license, there are three processes available: Traditional Licensing Process (TLP), Alternative Licensing Process (ALP), and Integrated Licensing Process (ILP). Many small hydropower developers prefer to use the TLP for flexibility. Because the ILP is FERC's default licensing process, applicants must request to use the TLP.

For hydro development on Bureau of Reclamation facilities where hydropower development is explicitly mentioned in the authorizing legislation, hydro permitting is handled by Reclamation (details below). For any individual project, determination as to whether FERC or Reclamation is the relevant federal permitting authority is governed by a Memorandum of Understanding between FERC and Reclamation.

In August of 2010, the Colorado Energy Office signed a memorandum of understanding with FERC to create a streamlining program for Colorado small, low-impact hydropower projects. The Colorado program is currently not in operation although one key benefit of the program is that it educated federal and state agency staff about FERC requirements.

For further information on the FERC authorization process for small hydropower projects and to get in contact with FERC directly, applicants can access the FERC Small/Low Impact Hydropower Website listed below:

https://www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact.asp

3A3. **Qualifications for Project Exemptions and Licenses**

i.) **FERC Jurisdiction For hydro projects**

A FERC license or exemption authorization is required to construct, operate, and/or maintain a nonfederal hydroelectric project that meets any one of the following conditions:[ix]

- Is located on navigable waters of the United States;
- Occupies lands of the United States;
- Utilizes surplus water or water power from a U.S. government dam; or
- Is located on a stream over which Congress has Commerce Clause jurisdiction, is constructed or modified on or after August 26, 1935, and affects the interests of interstate or foreign commerce.

Projects that interconnect with the power grid are considered to affect interstate commerce

because power can be exported from the state. This is true of both net-metered projects and projects planning to sell power to a utility under a power purchase agreement. In addition, since hydroelectric projects are frequently located in places with favorable flow characteristics, projects are typically located on navigable waters. Therefore, most hydroelectric projects will be required to file with FERC for either a license or an exemption authorization. [x]

ii.) **What Projects Are Eligible for an Exemption from Licensing**

5MW Exemption

The 5 MW Exemption applies to projects that will have a total installed capacity of 5 MW or less upon completion. To qualify for a 5 MW Exemption, a project must be located at:

1. a non-federal dam built before July 22, 2005, OR
2. a natural water feature that does not retain water behind any structure for head.

5 MW exemptions can be located on federal lands. But if the project involves non-federal lands, the applicant must own or have legal access to those lands. The regulations require the applicant to have "real property interest" (i.e., a deed, lease, right-of-way, easements, or an option to obtain one of these interests) to all non-federal lands necessary to develop and operate the project, including, if applicable, the reservoir that supplies water to the hydroelectric project. Applicants must possess "real property interests" when they apply for the exemption. In order to avoid delays and to qualify for an exemption, these property interests must be in order.

It is important to note that an exemption does not grant the power of eminent domain, as a license would. In addition, the exemptee must maintain its real property interests throughout the term of the exemption (i.e. if an applicant has a 5-year lease to use a powerhouse for the project, it must continue to renew the lease for the entire term of the exemption).

If a 5 MW Exemption applicant plans to utilize an existing dam, the project cannot require construction or enlargement of any impoundment structures, although repair and reconstruction of existing structures is allowed.[xi]

Conduit Exemption

To qualify for a Conduit Exemption, a project must meet the following criteria:

1. Utilize an existing manmade conduit built primarily for purposes other than power production (i.e., agricultural, municipal, or industrial consumption)
2. Be ≤15 MW if a non-municipal project, or ≤40 MW if a municipal project (specifically in the case of a facility constructed, operated and maintained by an agency or instrumentality of a State or local government solely for water supply for municipal purposes)

3. The powerhouse must be located entirely on non-federal lands, and the applicant must have property interest in those lands. The conduit itself may cross federal lands.

FERC refers to a project qualifying for the Conduit Exemption as a "small conduit hydroelectric facility." A conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity.[xii]

Important clarifying points related to Conduit Exemption eligibility criteria include the following:

1. In contrast to the requirements for a 5 MW Exemption involving non-federal land, applicants for a Conduit Exemption need only own the land on which the hydroelectric power generating facility will be located. This includes associated structures and equipment (i.e., the powerhouse and any intake and discharge pipelines) but excludes the conduit on which the hydroelectric facility will be located, as well as the transmission lines associated with the facility. The conduit must have been built primarily for purposes other than generating electricity. For example, it could have been built for agricultural, municipal, or industrial purposes.
2. The hydroelectric facility cannot be an integral part of a dam, and it cannot require the construction of a new dam for the purpose of power generation.
3. Water used for generating power must be discharged into one of the following: a) a conduit; b) a point of agricultural, municipal, or industrial consumption; or c) a natural water body, if the same or a greater amount of water discharged from the conduit with withdrawn downstream as part of the same conduit system.[xiii]

iii.) **The FERC Application Process for Both Exemption Types**

Because the exemption application process follows the Commission's Traditional Licensing Process, it is useful to understand the broader licensing process framework. The licensing process is designed to document environmental, engineering, economic, and other characteristics of an applicant's project. The process involves gathering information, which could result in studies, and consultation with interested resource agencies and members of the public. The documentation resulting from this process is provided in a final exemption or license application and forms the basis for FERC's decision-making. The documentation also helps FERC to determine if the project's complies with other federal laws, including the National Environmental Policy Act (NEPA).

In preparing conduit and 5 MW exemption applications, applicants should follow section 4.38(b) of the Commission's regulations. The FERC exemption templates available on FERC's small hydropower website under the column "Prepare Application" provide guidance for both conduit and 5 MW exemption applications.

The FERC licensing process is broken into two primary phases: Pre-Filing and Post-Filing Activity. Pre-filing is for information gathering and the beginning of consultation with stakeholders. Post filing activity is after a formal application is filed with FERC and FERC analyzes the project proposal and makes a licensing decision.

Pre-Filing Stage

The primary focus of the initial application phase, the "pre-filing phase," is to establish an understanding of issues associated with the proposed project.

The process of interacting and gathering feedback from stakeholders, agencies and the public, is called "consultation." This consultation plays an important role in providing the agencies and the public an opportunity to voice any concerns or request any studies that may be relevant to the proposed project. [xiv]

The consultation process is broken into three stages. The first two stages of consultation are completed during the pre-filing phase. The third stage of consultation begins when the applicant files its final application. Throughout the stages of the consultation process that occur during the pre-filing phase, the applicant is responsible for interacting directly with the many participating stakeholders. In some cases, FERC can be called on to resolve disputes. However, consultation is directly between the applicant and stakeholders during the pre-filing period.

Consultation between the applicant and any stakeholder (i.e. written letters or emails) should be included in the final exemption or license application in order to provide documentation of consultation with these stakeholders.

First Stage Consultation

The first stage of consultation focuses on engaging stakeholders in the exemption or licensing process and developing studies, if needed, that will be performed to support the application. As stakeholders, resource agencies, Indian tribes, and members of the public have an opportunity to specify which studies should be conducted to better understand the project and its impacts, and the applicant is responsible for conducting and reporting on the results of the studies.

These parties are referred to collectively as "stakeholders." FERC's website provides a search tool that generates an "initial consultation contact list." Each applicant should conduct their own search to obtain the most current information available at the time they initiate their application process and contact FERC to discuss the project consultation contact list. Letters will need to be sent to agencies and affected organizations providing the Initial Consultation Document, requesting consultation and comments on the proposed project. Consulting with the relevant federal and state agencies also ensures the applicant complies with other federal statutes, such as the

Endangered Species Act (ESA), the National Historic Preservation Act (NHPA), Magnuson-Stevens Fishery Act (Essential Fish Habitat), and the National Historic Preservation Act (NHPA). Those who must be contacted may include the following:

- U.S. Fish and Wildlife Service
- National Marine Fisheries Service
- National Park Service
- U.S. Environmental Protection Agency
- The federal agency overseeing any federal lands that may be used or affected by the project
- State agencies that oversee natural and resources including fish, wildlife, botanical resources, water quality and water resources
- State Historic Preservation Officer and Tribal Historic Preservation Officer
- Local, state, and regional recreation agencies and planning commissions
- Local and state zoning agencies
- Indian Tribes that may be affected by the project: Consult with the State Historical Preservation Officer (Colorado Historical Society) on Tribal contacts
- Landowners that may be affected by the project

Below is contact information for relevant Colorado organizations.

Mark Uppendahl	Colorado Division of Wildlife	303-291-7267	mark.uppendahl@state.co.us
Steven Turner	Colorado Historical Society	303-866-2776	steve.turner@state.co.us
Patty Schrader Gelatt	US Fish and Wildlife Service	970-243-2778 ex 26	patty_gellatt@fws.gov
John Hranac	CO Department of Public Health and Environment Water Quality	303-692-3586	john.hranac@state.co.us
Martin Hestmark	US EPA Denver Office	303-312-6776	Hestmark.martin@epa.gov
Matt Rice	American Rivers	303-454-3395	mrice@americanrivers.org
David Nickum	Trout Unlimited	720-581-8589	dnickum@tu.org
Kevin Rein	CO Division of Water Resources	303-866-3581 ex 8239	kevin.rein@state.us.com
Hugh Osborne	National Heritage Areas Coordinator	303-969-2781	hugh_osborne@nps.gov

At the start of the consultation process, the applicant should provide the Initial Consultation Document detailing the proposed project, identifying any effects of the project on environmental resources, any information needs or studies, and providing meaningful comments and recommendations on the proposed project.

Specific information required in the Initial Consultation Document (ICD) are listed on the FERC small hydropower web site. In general, the ICD includes but is not limited to the following:

- Detailed maps showing project boundaries and the location of the powerhouse and any additional facilities associated with the project, such as roads and transmission lines;

- A general engineering design of the proposed project, including a description of any proposed diversion of a stream through a canal or penstock;
- A summary of proposed operational characteristics of the project;
- Description of the environment likely to be affected by the project, and any plans to minimize environmental impacts;
- Information on stream flow and the water regime, such as the drainage area and monthly flow rates;
- A description of studies proposed to be completed; and
- A statement noting whether or not the applicant plans to pursue benefits available under the Public Utility Regulatory Policy Act of 1978 (PURPA).

See Additional details on the FERC web site.

Applicant Conducts a Public Meeting

The applicant must conduct a public meeting to explain its project (i.e., its facilities and operation), review any existing information, discuss the project's potential environmental effects, and find out if there are any needed studies to fill information gaps.

The public and all stakeholders should be invited to the meeting. The applicant must consult stakeholders ahead of time to determine a convenient time and place for the public meeting and to develop an agenda.

The meeting must be held no earlier than 30 days, but not more than 60 days, after the applicant initially contacted provided stakeholders with the applicant's project proposal. Thus, applicants should only release the information to the stakeholders (in Step 1) when prepared to conduct the public meeting.

The applicant must publish a notice about the scheduled meeting in a local newspaper at least 14 days prior to the meeting date. In addition, the applicant must provide FERC with written notice of the meeting and an agenda at least 15 days prior to the meeting date.

At the meeting, the applicant must provide an opportunity for visiting the site of the proposed project. In addition, the applicant must have on hand at the meeting copies of the project information initially sent to stakeholders.

Comments are Submitted to Applicant by Resource Agencies, Indian Tribes, and the Public

If a stakeholder plans to submit comments, they must be submitted in writing within 60 days of the public meeting. If a stakeholder is making a study request, the request should include the following information:

- The stakeholder's determination regarding which studies need to be completed by the applicant, including discussion of the basis for this determination;
- Recommendations and rationale regarding the methodology to be used in the studies; and
- A discussion of the stakeholder's understanding of resource issues associated with the project, as well as the stakeholder's goals and objectives for protecting those resources.

Stakeholders can contact FERC to request a 60 day extension to the comment period.

Depending on the environmental impacts of the project, studies may or may not be requested by stakeholders. If studies have been requested, the applicant should have a clear understanding of the studies that need to be conducted.

Fish & Wildlife Agencies Provide Cost Estimates for Setting Terms and Conditions for Exemption

The U.S. Fish and Wildlife Service and the Colorado Division of Wildlife may incur costs during review process of an application for exemption, and are entitled to reimbursement from the applicant. An exemption applicant must notify federal and state fish and wildlife agencies that it is seeking an exemption during the first stage of consultation (see Step 1 above). The federal and state fish and wildlife agencies must provide the applicant with a reasonable estimate of the total costs it anticipates it will incur to set mandatory terms and conditions for the proposed project, during the 90-day comment period set-out in the second stage of consultation (described below second stage consultation Step 3).

In some cases, the agency may choose not to charge the applicant any fees. If this is the case, the agency should provide the applicant with documentation that it plans to waive any fees. If the agency provides neither an estimate of costs or documentation of plans to waive fees during the 90-day comment period, the applicant must affirmatively state in its final exemption application that no federal or state fish and wildlife agency provided a cost estimate to set fees.

Resolve Disputes as Necessary

If studies are requested, stakeholders may disagree with the applicant about the appropriate studies to be conducted or information to be gathered. If such a disagreement arises, the disagreement can be referred to the Commission for resolution. The stakeholder requesting the dispute must file the request with the Commission and serve a copy of the written request for dispute resolution to the applicant and any affected resource agency or tribe at the same time it submits the request to the Commission. The applicant has 15 days to file written responses to the dispute. The Commission will resolve the dispute by letter.

First Stage of Consultation Completion

The comment period remains open for 60 days after the public meeting takes place. Stakeholders can request extensions and the period can last up to 120 days. There is always an option for stakeholders to provide input and comments throughout the FERC process. Requests for comment extensions need to be filed with the applicant and the Director of Energy Projects at FERC.

Second Stage Consultation

The second stage of consultation involves completion of studies planned during the first stage and the preparation of a draft exemption or license application.

Applicant Conducts Studies Requested by Stakeholders

An applicant must conduct the studies, and gather additional information that will fill in information gaps about the project. These studies need to be completed before filing the draft exemption or license application.

It is possible that a stakeholder could submit a request for the applicant to conduct an additional study after the end of the first stage of consultation. If the stakeholder can present sufficient justification for requiring the additional study, the applicant is expected to complete the requested study. However, the applicant can contact FERC to challenge the need for the additional study.

- *2. Applicant Provides Stakeholders with a Letter Requesting Review and Comment on the Following Materials:* Results of Studies and Information Gathering. The applicant must provide all stakeholders with results of the studies and information gathering efforts. After providing the study results to stakeholders, the applicant may propose measures to mitigate environmental impacts.
- Draft Application: The applicant must prepare a draft of all exemption or license application materials and provide copies to all stakeholders. The application materials should respond to any comments and recommendations made by stakeholders during the consultation process and include mitigation measures for any identified project effects on environmental resources.

Stakeholders Provide Applicant with Comments on Draft Application and Study Results

Stakeholders have 90 days after receiving the applicant's draft exemption or license application to provide comments on the draft application and study results.

Resolve Disputes as Necessary

If a stakeholder submits comments indicating a substantial disagreement with the material presented in the draft application or study results, the applicant must hold a meeting within 60 days of receiving those comments. The applicant must also provide FERC with written notice of

the meeting and an agenda at least 15 days before the meeting is scheduled to take place. After the meeting takes place, the applicant should draft a summary explaining how the disagreement was resolved. This discussion is also included in the exemption or license application materials.

If no major disagreements with the draft application and/or study results are raised by stakeholders, the applicant can begin to finalize the final exemption or license application with comments received by stakeholders on the draft application. [xv]

Third Stage Consultation

The third stage of consultation begins when the applicant files the final application for an exemption or a license. Included in the final application are the ICD, information gathered from studies plus information gathered from consultants and stakeholders.

Post-Filing Stage

The post-filing phase begins after FERC receives a final exemption or license application.

FERC Reviews Application for Adequacy

Upon receiving the final exemption or license application from an applicant, FERC reviews the application to determine whether it adequately complies with all regulatory requirements. FERC's findings are in one of three forms:

- The application is found adequate; all necessary information is included.
- The application is found "deficient" for failure to comply with all of FERC's filing requirements.
- The application is found "patently deficient" and is rejected if severe deficiencies exist in the application or if the project is not able to proceed for legal reasons. In this case, the application is rejected.

Applicant Corrects Deficiencies in the Application As Needed

If the application materials are deficient, an exemption applicant will be given up to 45 days and a license applicant will be given up to 90 days to correct the deficiencies. The corrected application will need to be resubmitted to FERC along with five copies. If an application is rejected, it can be resubmitted if the deficiencies are corrected.

At this time, FERC may require the applicant to submit additional information or documents if additional information is needed to understand the project proposal and the resources that may be affected by the project.

FERC Issues Notice that Application is Accepted for Filing

If the application complies with all regulatory requirements, FERC will notify the applicant and all participating stakeholders that the application is "accepted for filing." The notice will request that stakeholders review the application and file comments and recommendations with FERC. FERC will also publish a notice of the acceptance for filing in a newspaper in each county in which the project would be located.

Stakeholders Submit Comments / Terms and Conditions

Any agency or member of the public is free to submit comments on the application within 60 days of receiving FERC's notice that the application has been accepted for filing.

Federal and state agencies may specify terms and conditions that the applicant must meet as it moves forward with project construction and operation. Terms and conditions specified by both the state and federal fish and wildlife agencies are mandatory and included in the order granting an exemption. For a license, only federal agencies have mandatory conditioning authority and a water quality certification is required by the state.

Applicant Submits Reply Comments

The applicant will have 45 days after the end of the 60 day comment period to submit a reply to any comments filed on the project.

FERC Conducts Environmental Analysis

FERC staff completes an environmental analysis based on the record of facts regarding the proposed project. Conduit Exemption applications may be categorically excluded from NEPA requirements. The rationale for this is that a more comprehensive environmental analysis would have been completed for the site leading up to construction of the actual conduit upon which the proposed hydroelectric facility would be located.

FERC Issues Order Granting / Denying Exemption

Once FERC has completed its environmental analysis, FERC will issue an order granting or denying the exemption or license. When granting an exemption, the order will include a standard set of terms and conditions that apply to all exemptions and/or licenses. The order will also specify additional terms and conditions, including those submitted by federal and state fish and wildlife agencies. Terms and conditions are intended to ensure that the project will be developed in a manner that will minimize environmental impacts and reflect the best interest of the public.

If Exemption Is Denied, Applicant May Convert to License Application

FERC will make every effort to have the application be focused on the right path for approval but if FERC denies the applicant an exemption, the applicant can convert its exemption application into a license application if:

- Within 30 days of being denied an exemption, the applicant provides FERC with written notice of its intent to convert to a license application
- The full set of application materials qualifies the applicant to receive a license for the proposed project.[xvi]

3A4. **Federal Permitting through the Bureau of Reclamation: Lease of Power Privilege**

Bureau of Reclamation

For a hydropower project on a Reclamation facility, if the relevant federal authorizing legislation explicitly mentions hydropower as an authorized use, Reclamation, not FERC, oversees hydro permitting through a process known as a Lease of Power Privilege (LPP).

A Lease of Power Privilege (LPP) is a contractual right given to a non-Federal entity to use a Reclamation facility for electric power generation consistent with Reclamation project purposes. Reclamation's main concern in awarding an LPP is that the integrity of Reclamation facilities not be impaired. A new hydro plant must not interfere with existing operations, jeopardize existing water rights, or create any safety problems.

Under a LPP, the lessee is responsible for compliance with the National Environmental Policy Act (NEPA) and the Endangered Species Act (ESA). Reclamation is responsible for lease development, as well as review and approval of designs, plans and specifications and NEPA documentation.

Under a LPP, title of the federal facility remains with Reclamation. Title of the hydro plant is with the lessee unless contracted otherwise. Reclamation also has the first right to take over the hydro plant in the event of a sale or default.

Once selected for development of a LPP, the potential lessee must develop a cost recovery agreement with Reclamation for Reclamation costs related to development of the lease, including, but not limited to: NEPA, review of designs, administrative costs, construction, operation, maintenance and security.

Initiation of a Lease of Power Privilege application starts with a simple application letter to Reclamation requesting a Lease of Power Privilege. In response, Reclamation posts a formal solicitation in the *Federal Register* asking for LPP applications.

After selection of the lessee, the LPP process cannot be finalized until after completion of the NEPA process. Assuming that the environmental process does not uncover any problematic

issues, yielding a "Finding of No Significant Impact," the process moves to final negotiation of the LPP. Once signed, the typical LPP length is 40 years. Additional information regarding the LPP process is available on Reclamation's Lease of Privilege website (see Appendixes).

Step 3B. Finance

3B1. **Grants and Loans**

Federal

The Bureau of Reclamation's WaterSMART grant program can help fund hydro project development. Eligible WaterSMART grant applicants include States, Indian tribes, irrigation districts, water districts, or other organizations with water or power delivery authority located in the western United States. Successful WaterSMART hydro grant recipients typically include not only a hydro project but also some type of additional public benefit, such as salinity reduction or water conservation.

The USDA's REAP program (Rural Energy for America Program) can provide loan guarantees up to $25 Million, project feasibility grants up to $50K covering 25% of study costs, and renewable energy project grants up to 25% of project costs with a maximum of $500K. Hydropower is an eligible project type for REAP grants. Eligible REAP grant applicants are typically rural small businesses.

State

The Colorado Water Resources and Power Development Authority (CWRPDA) has a feasibility grant program which can provide up to $15,000 in 50% cost-shared funds to support feasibility studies, permitting, final design and other costs associated with FERC or Bureau of Reclamation permitting processes.

CWRPDA also has a small hydropower loan program which can lend up to $2M at a rate of 2% for project construction. CWRPDA-eligible borrowers include cities, towns, counties, water districts, water and sanitation districts, metropolitan districts, water conservancy districts, water conservation districts, and irrigation districts. Loans are limited to a maximum of $2 million per governmental agency. The interest rate is two percent, and the maximum term is twenty years.

The Colorado Water Conservation Board (CWCB) also has a hydro loan program that can finance the engineering and construction of hydro projects with loan terms of 30 years at an interest rate of 2%. There is no maximum loan amount; however, borrowers are required to first apply to the CWRPDA for the initial $2 million of funding and the CWCB loan will the

finance the remainder of the project costs. In addition to governmental agencies, the CWCB can also lend to agricultural borrowers.

3B2. **Utility Incentives**
Some Colorado utilities have incentives which can support hydro project development. For example, Holy Cross Energy has a hydro tariff with a standing offer to purchase hydropower from projects less than 100 kilowatts.

Step 3C. Interconnection

3C1. **Interconnection Study**
The cost, complexity and process for grid interconnection depends upon the scale of the project and type of interconnection. As noted above, for a smaller project, a simple net metering agreement and interconnection agreement can typically be arranged with the local utility without difficulty. For larger systems, a utility may require an interconnection study to determine whether or not the project would cause any adverse impacts on utility infrastructure of operations. The interconnection study might be completed by the utility itself or by an engineering firm approved by the utility. Costs of the interconnection study will need by paid for by the project developer.

STEP 4 Final Design and Construction

Step 4A. Construction Contract Options, List of Engineering Firms and Related Resources

Once a small hydropower project has been found to be feasible, a permitting approach determined and financing is arranged, the project will enter into final design and construction. Depending on the size of the project and the owner's acceptable level of risk, several contracting options are available. A few general contracting options are discussed below. There is a significant amount of flexibility within these options and negotiations with the design team and the construction team can tailor these options to the owner's needs.

Design-Bid-Build

The traditional contracting method for construction projects is Design-Bid-Build. The owner will hire an engineer to complete the final design, develop construction drawings, and specify materials and methods of construction. The engineer will also prepare bid documents and solicit fixed bids from contractors. A selection process based on qualifications, experience and cost will be used to select a contractor to construct the plant. Generally the engineer, or another construction management firm, will manage construction providing quality control and management services.

An estimate for the final construction cost is known after the engineering is completed, and the construction cost is finalized only after the selection of a contractor. The owner is involved in the design process and works with the engineering firm to ensure the project is designed to the owner's specifications.

Engineer-Procure-Construct

Under an EPC contract, the contractor designs the installation, procures the necessary materials and builds the project, either directly or by subcontracting part of the work. In some cases, the contractor carries the project risk for schedule as well as budget in return for a fixed price. This approach will reduce the risk associated with cost for the owner as the cost is known at the time of contracting, although the owner will be less involved in the design process.

Design-Build

Design-Build is similar to EPC in the fact that there is one point of contact for both design and construction. A design-build firm handles both the engineering design and the construction. Generally the owner is more involved in the design and assumes some risk. The design-build firm and the owner share risk associated with changes to the design, this division will be stipulated in the contract documents. This method does not insure a fixed-firm price at the time of contractor selection, but it does allow for increased owner involvement.

Step 4B. Construction Management

Depending on the contracting method chosen for the project, construction management is assigned to the appropriate party. Management of construction generally includes the following responsibilities:

1) Contract management including selection, award, document management and invoicing
2) Quality assurance including inspection and testing
3) Coordination of contractors, scheduling and change order management

Engineering companies generally provide construction management services and there are also firms that specifically provide construction management services. A list of Colorado hydropower consultants is included in the Appendixes.

Step 4C. Inspection Approval, State Electrical Board

As noted above, project approval will also require approval by a state electrical inspector, with the applicable inspection guidelines varying depending upon whether or the project is net metered. For a net metered system, inspection guidelines require that all electrical equipment be U.L. listed and be installed and used in a manner consistent with the use on the equipment nameplate. This can present difficulties for small hydropower systems where it is common to

use small motors as generators since motors and generators are identical. The simplest way to avoid this problem is to purchase a motor which is labeled as a generator in order to avoid any complications during the inspection process. If needed as a fallback measure, it is possible to petition the Colorado State Electrical Board requesting issuance of a formal waiver, providing formal permission for use of a motor as generator. The State Electrical Board may request on-site certification by an engineering company to test and commission the system prior to issuing a permit. A few companies providing this service are listed in the appendix under permitting.

Step 4D. Construction Permitting

In addition to the permits listed above, several permits are generally obtained by the contractor prior to construction. The contract documents should outline the responsible party for obtaining these permits and the associated timelines.

Building and Use Permits

Requirements for building permits vary depending on the municipality, and the zoning within the municipality. Check local codes to verify requirements for construction of a powerhouse on non-federal land. Some municipalities have begun including hydropower plants in their land use codes, although this is infrequent. For example, Pitkin County provides the land use code for hydropower plants on their website.

Construction Dewatering

The Colorado Department of Public Health and the Environment, Water Quality Control Division also regulates Construction Dewatering Activities. If groundwater is encountered during excavation which may need to be discharged into groundwater or surface water, a certification under the Construction Dewatering (CDW) general permit is required. Generally Excavation Contractors are aware of this permit and will include the cost of obtaining this permit in the cost of construction of the facility. The State of Colorado released a guidance document addressing frequently asked questions pertaining to Construction Dewatering permits.

STEP 5 Commissioning and Communication

Once a project is completed, depending on the size and type of project, it may make sense to hold some type of “flip the switch” event to thank project stakeholders, celebrate success and secure press coverage – helping to make the project a model for others to follows. A project

commissioning event and press release can help to maximize the positive publicity and extend the impact of the project.

Figure 70: "Flip the Switch" Event for Humphreys Hydro Project, near Creede, CO

Appendix

1. Legal Resources for Water Rights in Colorado

I. Citizen's Guide to Colorado Water Law prepared by the Colorado Foundation for Water Education
II. Non-Attorney's Guidebook to Colorado Water Court, Colorado Department of Natural Resources, Division of Water Resources
III. Guide to Colorado Well Permits, Water Rights and Water Administration, September 2012, Colorado Department of Natural Resources, Division of Water Resources

2. Hydrology Resources

I. USBR Water Measurement Manual

II. Colorado Decision Support System – Historic Diversion Records

III. Colorado Decision Support System – Streamflow Stations

IV. Colorado Division of Water Resources – Surface Water Conditions, stream gages

V. USGS – Colorado Water Science Center – Stream Gages

3. Topography Resources

I. USGS Topographical Maps – The National Map

II. USDA Geospatial Data Gateway – Digital Elevation Models and Aerial Photography – GIS capabilities required

III. County elevation data (Mesa County example) – GIS capabilities required

4. Head Loss Resources

I. Calculator for head loss in pipes using Hazen-Williams Equation

II. Hazen-Williams Coefficient for penstock materials

5. Turbine Manufacturers

I. Very small hydropower turbine & generators appropriate for net metering or off the grid applications.

Manufacturer	Website	Name	Turbine Type
Energy Systems and Design	www.microhydropower.com	LH1000 Stream Engine	Propeller Turgo
Asian Phoenix Resources	www.powerpal.com	PowerPal Low Head PowerPal High Head	Propeller Turgo
Harris Hydroelectric	http://www.thesolar.biz/harris_hydro.htm	Harris Turbine	Pelton
Scott	http://www.absak.com/catalog/product_info.php/cPath/33_89_91/products_id/1370	Scott Cross Flow Turbine	Cross Flow
Power Spout	www.powerspout.com	PowerSpout PowerSpout Low Head	Pelton Propeller

II. Small Turbine Distributors:

ABS Alaskan
http://www.absak.com/

Energy Alternatives
www.energyalternatives.ca

III. Mechanical- hydro resources:

Jordon Whittacher

Two Dot Irrigation and Supply LLC

Leadore, Idaho

208-768-2058

IV. Traditional turbines and generators, offering "water to wire" packages

Manufacturer	**Website**	**Turbine Type**
Small		
Cornell Pump Company	http://www.cornellpump.com/products/hydroturbines.html	Pumps as turbines
Canyon Hydro	www.canyonhydro.com	Pelton Francis Cross Flow Kaplan
Rentricity	www.rentricity.com	Pumps as turbines

Medium		
Canadian Hydro Components	www.canadianhydro.com	Kaplan Propeller Francis
Dependable Turbines LTD	www.dtlhydro.com	Kaplan Propeller Francis Turgo Pelton Pumps as turbines
Toshiba International	http://www.tic.toshiba.com.au/hydro-ekids__8482_/	Propeller
Pentair Tamar	http://www.southerncross.pentair.com/	Kaplan Francis Pelton
Ossberger	www.hts-inc.com/ossbergerturbines.html	Kaplan Movable Powerhouse (Kaplan) Cross Flow
Gilkes	http://www.gilkes.com/	Francis Turgo Pelton
Mavel	www.mavel.cz	Microturbines (propeller) Kaplan Francis Pelton
Large		
Voith Hydro	http://us.voith.com/en/products-services/hydro-power/small-hydro-power-plants-552.html	Kaplan Francis Pelton Ecoflow
Andritz	http://www.andritz.com/no-index/pf-detail?productid=9218	Propeller Francis Pelton
Alstom Power	http://www.alstom.com/power/renewables/hydro/turnkey-power-plants/small/	Kaplan Francis Pelton

V. Emerging Technologies that are new to the market or not yet commercially available or implemented in the US.

Manufacturer	Website	Turbine
Hydrokinetics		
Alternative Hydro Solutions	www.althydrosolutions.com	Darrieus Water Turbine
Hydrovolts	www.hydrovolts.com	Canal turbine
New Energy Corp	www.newenergycorp.ca	EnCurrent
Hydro Green Energy	www.hgenergy.com	Lock+ and Dam+
Hydrodynamic Screws		
Ritz-Atro	www.ritz.atro.de/2006/index_neu.html	Archimedean Screw
Andritz	http://www.andritz.com/products-and-services/pf-detail.htm?productid=8775	Archimedean Screw
ReHart	www.rehart.de	Archimedean Screw
HydroCoil Power	www.hydrocoilpower.com	Small screw type turbine
Low Head Turbines		
Natel America	www.natelenergy.com	Hydroengine
MJ2 Technologies SAS (VLH Turbine)	http://www.vlh-turbine.com	Low Head (Kaplan)
Propeller Turbines		
Amjet	http://amjetturbinesystems.com/	Propeller
Clean Power	http://www.cleanpower.no/Home.aspx	Propeller
In-Pipe Turbines		
Lucid Energy	http://www.lucidenergy.com/lucid-pipe/	Vertical Axis

6. Civil Works Resources

I. Gates and Checks:

Golden Harvest, Inc.

Obermeyer Hydro

Safety Gates LLC

Waterman Industries

II. Screens and Trashracks:

Atlas Polar Hydro Rake Systems

Farmers Screen

Hydro Component Systems

Hydrolox

Hydroscreen, LLC.

International Water Screen

Intake Screens Inc.

Lakeside Equipment Corp

Norris Screens

7. Controls Resources

Powerbase Automation Systems Inc.

Thomson and Howe Energy Systems Inc.

8. Permitting Resources

I. USACE Colorado Offices
II. State of Colorado Water Quality Certification fulfilling the requirements of the Clear Water Act Section 401
III. Pitkin County Land Use Code (Section 4-30-50 (k))
IV. Construction Dewatering permits FAQ
V. State Electrical Board – Electrical certification with on–site testing service companies:
    a. Intertek Testing Services NA, Inc. (303)-493-5421 matthew.powelka@intertek.com

9. Construction Costs Resources

EPRI, 2011, "Quantifying the value of Hydropower in the Electrical Grid: Plant Cost Elements", Final Report 1023140, Palo Alta, CA

10. Small Hydropower Consultants in Colorado

AECOM
http://www.aecom.com/

Applegate Group, Inc.
www.applegategroup.com

Black & Veatch
www.bv.com

Community Hydropower Consulting
970-221-4474

HDR
http://www.hdrinc.com/markets/power/renewable-energy/project-types/hydropower

Hutton Consulting, Inc.
303-908-2178

Hydrowest, Inc.
http://www.hydrowest.net/

Knight-Piesold Consulting
http://www.knightpiesold.com/en/

SGM, Inc.
www.sgm-inc.com

Telluride Energy
www.tellurideenergy.com

URS Corporation
www.urscorp.com

11. Construction Companies with Hydropower Experience

Moltz Constructors
http://moltzconstructors.com/

Mountain States Construction
http://64.146.239.120/mtstates/index.php?option=com_frontpage&Itemid=1

Gracon Corporation
http://www.graconcorp.com/

Garney Construction
http://www.garney.com/

12. Case Studies

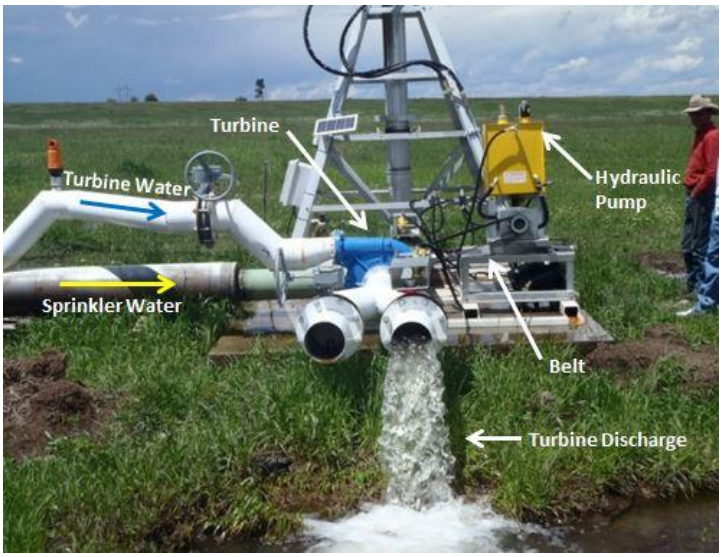
I. Bear River Ranch Hydro-Mechanical Center Pivot Irrigation Project

Summary

When confronted with rising water costs and low crop yields, Bear River Ranch, located near Steamboat Springs, installed a hydro-mechanical system to power its center-pivot irrigation system. This system uses the power of falling water to directly drive and pressurize the center pivot; this eliminates the need for electricity and significantly reduces operating expenses. The turbine uses 126 feet of head and 560 gpm to produce the equivalent of 5.2 kW of power which drives the center pivot. The $13,000 project was funded through $6000 in support from NRCS, yielding out of pocket cost to the ranch of$7000 and an expected payback of slightly over 3 years.

Background

The Natural Resource Conservation Service (NRCS) encourages water conservation by supporting the conversion of flood irrigation to sprinklers and also supports renewable energy for on-farm applications. By working with the NRCS for project design and financial assistance, Bear River Ranch was able to achieve both NRCS goals. A center pivot sprinkler was chosen as the water conservation measure, which uses significantly less water than the previous method of flood irrigation. A hydro-mechanical system was installed to eliminate the energy required to power the center pivot.



Design and Technical Details

The photograph at right shows the key components of the system: a turbine that powers the hydraulic pump through use of a connecting belt, and water supply lines to power the turbine and provide water to the sprinklers. A single, supply pipeline originates from a settling pond at a point 150 feet higher in elevation. This elevation difference pressurizes the water in the pipeline. Just before reaching the center pivot, the pipeline splits into two smaller supply pipes as shown in Figure 1; the pressurized water powers the turbine (via the pipe denoted with a blue arrow) and supplies the sprinklers (via the pipe denoted with a yellow arrow). The turbine

is attached to a shaft which drives a belt connected to the hydraulic pump. The hydraulic pump powers the drive system that moves the center pivot wheels and turns the sprinkler system.

Hydro-mechanical systems are relatively simple, so complex safety and operational procedures are typically not necessary. Because the use of hydro-mechanical systems is relatively rare, a lack of institutional knowledge has prevented their widespread use to date.

The Bear River Ranch turbine produces an equivalent of 5.2 kW or 7 HP to power the hydraulic pump on the center pivot sprinkler system. The hydraulic pump powers the drive system that turns the sprinkler, and the sprinkler is pressurized through gravity. No pumps, motors or electrical connections are required, resulting in very low annual operational expenses and minimal maintenance. Because it does not produce electricity, the project is not regulated by the Federal Energy Regulatory Commission.

The center pivot is operated only during irrigation season, with operation dictated by the crop's water demand. A T-L Irrigation hydrostatic center pivot with manual speed control was selected for the sprinkler system and a Cornell Pump (5TR5) was selected as the turbine. Cornell pumps are easily obtainable due to their dual purpose. Most pumps can be used for both pumping and as a turbine without any modification.

Construction of the hydro-mechanical system was a fast and simple process, spanning only one non-irrigation season. The center pivot distributor, B&B Irrigation, consulted with Jordan Whittaker of Two Dot Irrigation to select the turbine and design the connection. Because the turbine and hydraulic pump are belted together, their power outputs are essentially equivalent. As such, the turbine was sized to provide 7 HP or 5.2 kW which corresponds to the power needed for proper operation of the hydraulic pump. The turbine uses a flow of 560 gpm at the available 126 feet of working head to provide the 7 HP to the hydraulic pump.

Maintenance of the system is very simple. The turbine will need to be maintained as a pump would, with occasional bearing greasing. The center pivot machinery and turbine are generally given a useful lifetime of 20 years, although with proper operation and maintenance, they can last much longer. Premature wear due to debris and sediment in the water is possible and

could reduce the expected lifespan of the turbine so care must be taken to adequately filter the water prior to its entry into the system.

Economics

NRCS support the project in both the design of the irrigation system and partial funding of the entire project through the Environmental Quality Incentives Program (EQIP) program. EQIP provides financial and technical assistance to farmers and ranchers for the planning and implementation of natural resource conservation efforts. During 2011, EQIP allocated over $26 million for nearly 800 projects in Colorado. For Bear River Ranch, the NRCS grant lowered installation costs enough to make NRCS the only outside source of funding needed.

The only cost incurred which varied from that of a traditional, electricity-driven center pivot is that of the turbine; the center pivot sprinkler and pipeline costs were equivalent to traditional center pivot installations. The purchase of the turbine amounted to $13,000 to which the NRCS contributed $6,000, making the out-of-pocket expense for the system $7,000. The system saves estimated annual energy costs of approximately $2,100. Power to spin to the center pivot could alternatively have been obtained through either a diesel generator or grid interconnection if Bear River Ranch had opted for a traditional center pivot irrigation system, but this would result in annual fuel/electricity expenses. If electricity had been extended to the center pivot location, it would have cost $22,000. Center pivot systems using diesel or electricity would have higher installation costs and would have resulted in higher annual expenses. With the hydro-mechanical system, the initial investment by the ranch of $7,000 will be recaptured in 3.3 years of energy savings.

Lessons Learned

The project ran successfully through the 2012 irrigation season with no problems reported and increased crop yields using less water than had historically been used with flood irrigation. Many of the ranchers in the area are expressing an interest in installing the same type of system. Some have submitted applications to the local NRCS office, which is hoping to offer design services for this type of system. Such a system can potentially be replicated throughout Colorado in areas where sufficient pressure can be generated using at least 100 to 150 feet of fall.

II. Town of Basalt Small Hydro Project

Summary

The Town of Basalt built a 40 kW hydro system utilizing water delivered to the Town's water treatment plant which will generate an estimated 300,000 kWh annually. The project was funded through a grant from the Colorado Energy Office as well as an innovative energy pre-purchase agreement with the local electric utility, Holy Cross Energy. Holy Cross Energy provided $300,000 to the Town to pay for project construction in return for a future repayment of 6,000,000 kWh from the project.

Background

The Town of Basalt is a small mountain community located between Carbondale and Aspen. Basalt began looking into its hydro potential due to its environmentally conscious citizenry with a long standing desire to develop the area's rich hydro potential. Basalt's Green Team, a committee of residents and elected officials, started exploring the idea of small hydro -- eventually leading to the decision to install a small hydropower project utilizing flow from two nearby springs being piped down to the town's water treatment plant.

Project Design and Technical Details

The project has a generating capacity of 40kW, generating an estimated 300,000 kWh annually at full capacity. The project utilizes water from two springs -- Basalt Springs and Luchsinger Springs -- and does not affect any stream flow. Through pipeline improvements -- including slip-lining, valving and installations of ductile iron piping -- the springs provide the needed flow for a small hydro project totaling approximately 2.0 cfs. The piping provides approximately 345 feet of head, yielding net pressure at the turbine of 140 to 160 psi. Based on the head and flow, a constant flow variable speed turbine was selected. The project construction timeline was approximately one year.

Two different factors drove decisions regarding the siting of the project: a desire to minimize the visual impact of the structure, and powerhouse placement to ensure maximum generating capacity. The expected lifetime of the powerhouse building is 100 years and 20 years for the mechanical equipment and controls equipment.

The Town enlisted the assistance of an outside consulting firm with experience in the design and development of similar projects. The turbine, generator and controls for the project were provided by Canyon Hydro. The equipment has been working without difficulty since project commissioning.

The town installed equipment at the powerhouse to provide warning notification of problems, providing added safety to both equipment and people. Project monitoring is tied into some of the same monitoring equipment as is used for the water filtration plant in order to lower monitoring costs.

Challenges

The biggest challenge to the project has been related to water rights, which has inhibited the project from operating at full capacity, yielding reduced annual estimated generation of 175,000 kWh. The Town is pursuing additional water rights.

Project Economics

The hydro project cost was approximately $207,000 which included ancillary work; however this cost does not included pipeline work to accommodate the pressures necessary to support the hydro, although the pipeline work would probably need to have been done anyway related to the town's water supply needs. The total costs for the project, including both the pipeline work (much of which was necessary regardless of hydro generation) as well as the hydro equipment, was approximately $394,000. Financing for the project was provided by Holy Cross Energy and the Colorado Energy Office.

The Colorado Energy Office supplied the project with $119,000 in ARRA (federal stimulus) grant funds. Holy Cross agreed to finance up to $300,000 which was scheduled to be repaid through the electrical generation of the plant, estimated at 6,000,000 kWh (for a Holy Cross Energy loan of $300,000). Electricity generated by the project is being used to pay down what is effectively a no interest loan provided by Holy Cross Energy. By having Holy Cross supply the needed money for the project's upfront construction costs, the Town avoided taking out a loan, avoiding years of loan interest payments, ultimately saving approximately $60,000 in interest payments (assuming a 20 year loan at 2%). The project's generated electricity will be provided to Holy Cross until the initial

$300,000 is paid off, after which point the Town will retain the revenue from electricity generated by the project.

The expected payback period involved several varying factors, including annual operations and maintenance costs of approximately $1500 annually. At maximum production, the plant is expected to generate 300,000 kilowatt hours annually. At a power purchase rate of $.08 per kilowatt hour, revenue is approximately $24,000 per year, yielding a payback of about 11.4 years -- a best case scenario based upon maximum annual generation. The Town anticipates that the actual payback period may be closer 20 years based upon annual generation of 175,000 kWh.

Lessons Learned

Perhaps the most important part of the success of the project was the town's partnership with Holy Cross Energy -- without whose assistance the town probably could not have completed the project – underscoring the importance of effective partnerships to project success. In addition to Holy Cross Energy and Colorado Energy Office, additional project partners included Boundaries Unlimited, Western Pipeway, Teagle Excavating and Martinez Western Construction.

One of the principal project barriers was federal permitting. Basalt's project moved through the FERC permitting process with extensive assistance from the Colorado Energy Office FERC streamlining program. However, based upon the town's experience with the costs and time required to comply with FERC requirements, the town has decided that it would best to wait until pending federal small hydro permitting reform legislation becomes law before seeking to proceed with any additional small hydro projects.

13. Sample Power Purchase Agreement and Interconnection Agreement

Agreement for Electric Service - Large Power

Agreemen[redacted] 2010 between EMPIRE ELECTRIC ASSOCIATION, INC. (hereinafter called the "Cooperative"), and CORTEZ CITY OF (hereinafter called the "Applicant"), a Governmental Entity.

The Cooperative shall sell and deliver to the Applicant, and the Applicant shall purchase all of the electric power and energy which the Applicant may need at the location described in Exhibit A, attached hereto and by this reference made part hereof, up to 300 KVA, upon the following terms:

1. SERVICE CHARACTERISTICS

a. Service hereunder shall be alternating current, sixty cycles, Three Phase 277/480 volt 4-wire.

b. The Applicant shall not resell electric power and energy purchased hereunder, unless written approval is first obtained from the Cooperative.

2. PAYMENT

a. The Applicant shall pay the Cooperative for services hereunder at the rates and upon the terms and conditions set forth in Schedule 6ABC (Large Power), attached to and made a part of this Agreement or any amendment thereof made by the Board of Directors of the Cooperative and approved by the Colorado P.U.C. and Utah P.S.C., if said commission or commissions has jurisdiction. In any event, the Applicant shall pay the Cooperative not less than $191.25 per month and in no event less than $191.25 per year, for service or for having service available hereunder during the term hereof.

b. The initial billing period shall start when Applicant begins using electric power and energy, or 30 days after the Cooperative notifies the Applicant in writing that service is available hereunder, whichever shall occur first.

c. Bills for service hereunder shall be paid at the office of the Cooperative in Cortez, State of Colorado.

Such payments shall be due on the tenth day following the date the bill is mailed for service furnished during the preceding monthly billing period.

If the Applicant shall fail to make any such payment within ten (10) days after such payment is due, the Cooperative may discontinue service to the Applicant upon giving seven (7) days written notice to the Applicant of its intention to do so, provided, however, that such discontinuance of service shall not relieve the Applicant of any of its obligation under this Agreement.

Page 1 of 4

Large Power Agreement

3. **MEMBERSHIP**

An applicant who becomes a member of the Association agrees to be bound by its Rules and Regulations, the Bylaws, and provisions of the Articles of Incorporation.

An applicant who chooses not to become a member agrees to be bound by the Rules and Regulations and applicable portions of the Bylaws and Articles of Incorporation, and shall not participate in Stockholder Meetings, Director Elections or enjoy other member privileges.

4. **CONTINUITY OF SERVICE**

The Cooperative shall use reasonable diligence to provide a constant and uninterrupted supply of electric power and energy hereunder. If the supply of electric power and energy shall fail or be interrupted, or become defective through act of God, Governmental authority, natural causes, public enemy, accident, strikes, labor trouble, required maintenance work, inability to secure right-of-way, or any other cause beyond the reasonable control of the Cooperative, the Cooperative shall not be liable for any damages caused thereby.

5. **RIGHT OF ACCESS**

Duly authorized representatives of the Cooperative shall be permitted to enter the Applicant's premises at all reasonable times in order to carry out the provisions hereof.

6. **TERM**

This Agreement shall become effective on the date first above written and shall remain in effect until 1 months following the start of the initial billing period. After the initial term, this contract will continue and electric service will be provided in accordance with the Rules and Regulations and current rate schedules until terminated by either party.

7. **SUCCESSION AND APPROVAL**

a. This Agreement shall be binding upon and inure to the benefit of the successors, legal representatives and assigns of the respective parties hereto.

b. This contract shall not be effective unless approved in writing by the Administrator of the Rural Utilities Services, if such approval is required.

c. Applicants and guarantors agree to pay Cooperative all costs of collection, including a reasonable attorney's fee, upon failure to pay for service in the matter herein agreed upon. The Applicant shall provide absolute and unconditional guarantees for the term of this agreement, as deemed sufficient at the sole discretion of the Cooperative. All guarantees shall be continuing, absolute, unconditional, joint, and several. Guarantors waive presentment, demand, protest, notice of dishonor, and all other notices, including the right to require the Cooperative to bring action against the Applicant.

Large Power Agreement

8. AID IN CONSTRUCTION

The Applicant shall pay the Cooperative the sum of $40,000.00 for the cost of facilities required to make service available to the Applicant on or before commencement of construction of such facilities.

9. ADDITIONAL CONTRACT TERMS

Please sign, date & return one copy of the enclosed interconnection agreement

IN WITNESS HEREOF, the parties hereto have executed this Agreement all as of the day and year first written above.

EMPIRE ELECTRIC ASSOCIATION, INC.

By - President: [redacted] /2010

Attest - Secretary [redacted] /2010

Applicant: CORTEZ CI[redacted]

By - Applicant: [redacted] 08/09

Title of Officer*: Mayor

Attest - Secretary: [redacted] 08/09

Guarantor:

Guarantor signature: _____ Dat _____

Guarantor signature: _____ Dat _____

* If other than president, vice president, partner, manager, agent, or owner, a power of attorney or appropriate resolution of authority must accompany contract.

Page 3 of 4

Large Power Agreement

Exhibit A

Description and Location of Service

Use of service: micro hydro electric plant

Service will be made available on or before: _____

Size of largest motor: _____

Service Address: [redacted]

Location:

Township, Range, Section: _____

Applicant: [redacted]

Applicant Address:

[redacted]

Show the location of the point of service in section tract below. Also show existing electric lines, roads, service disconnect amperage and voltage, etc. that may be related to this service.

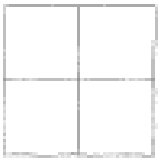


Exhibit B - EEA and City of Cortez Interconnection Agreement

INTERCONNECTION AGREEMENT

This agreement ("Agreement") dated this 14th of ~~November, 2009,~~ January 2010 by and between Empire Electric Association, Inc. ("EEA") and the City of Cortez, ("Customer"), jointly referred to as the parties ("Parties").

Whereas, Customer owns or intends to install and own an electric generating facility ("Facility") on Customer's premises located near the Customer's water treatment facility in Montezuma County northeast of Cortez, Colorado, for the purposes of generating electric power and energy; and

Whereas, Customer wishes to sell and EEA, through an agreement with Tri-State Generation and Transmission, Inc., is willing to purchase power and energy produced by the Facility;

Now, therefore, the parties agree:

1. Generating Facility: Customer's Facility shall consist of a micro hydroelectric generating facility located on the Customer's premises, with a capacity of up to 240 kilowatts (kW). Said Facility will be interconnected and operated in parallel with EEA's distribution facilities.

2. Conditions for Interconnection: Customer may interconnect with EEA's electric system and operate its Facility once all of the following have occurred:
   a. Upon completing construction, Customer has caused the Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction;
   b. Customer has returned a certificate of completion to EEA, with notice of the anticipated commercial production date at least 45 days prior to the commercial production date;
   c. EEA has completed its review of the Facility, which review shall be conducted by EEA at its own expense within ten business days after receipt of the certificate of completion and shall take place at a time agreeable to the Parties, and provide Customer a written statement that the Facility has been reviewed and, if necessary, what steps it must take to pass the review. This review is solely for EEA's purpose and is not a review of the adequacy of Customer's facility;
   d. An interconnection study as described in the Colorado Public Utility Commission Rules regarding interconnection of generation has been conducted. EEA will advise the Customer if the proposed installation is suitable for interconnection pursuant to these rules. If, as determined in the interconnection study, modifications are required to EEA's system to accommodate the facility these modifications will be performed at the Customer's expense. The cost for such modification is $40,000 due in advance of construction. Customer shall provide the interconnection on Customer's side of the meter. The metering system used by EEA shall include, at Customer's own expense, all equipment necessary to meet applicable safety, power quality, and interconnection requirements established by EEA's electric service requirements, policies, rules and regulations, the National Electric Code, National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories; and

e. EEA has provided Customer written approval of the Customer's protection-isolation method to ensure generator disconnection in case of a power interruption from EEA.

3. Disconnect System: Customer may be required by EEA to furnish and install on Customer's side of the meter a safety switch which shall be capable of fully disconnecting the Customer's energy generating equipment from EEA's electric service. The disconnect switch shall be located adjacent to EEA's meters and shall be of the visible break type in a metal enclosure which can be secured by a padlock. The disconnect switch shall be accessible to EEA personnel at all times.

4. Disconnection:
   a. Until the following has been remedied, EEA may disconnect the Facility in the event of improper installation:
      i. failure to return the certificate of completion, or
      ii. failure to perform modifications required by the interconnection study as required by section 2 above.
   b. EEA may temporarily disconnect the Facility upon the following conditions:
      i. For scheduled outages;
      ii. For unscheduled outages, overload of EEA's supply, or emergency conditions;
      iii. To maintain safe electrical operating conditions or, if in EEA's sole judgment, the Facility at any time adversely affects EEA's operation of its electrical system or the quality of EEA's service to other customers; or
      iv. If the Facility does not operate in the manner consistent with terms and conditions of this Agreement.
   c. EEA shall inform Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.
   d. In the event this Agreement is terminated, EEA shall have the right to disconnect its facilities and/or direct the Customer to disconnect its Facility.

5. Termination: This Agreement may be terminated under the following conditions:
   a. By Customer by providing written notice to the utility; or
   b. By EEA if the Facility fails to operate for any consecutive 12 month period or Customer fails to remedy a violation of any of the terms and conditions of this Agreement.

6. Price and Payment: At the end of each billing period, the Customer will be paid for energy delivered to the EEA system per the terms and conditions of the existing power sale contract between the Customer and EEA. The Customer will be billed at the current large power rate for any energy consumed within the facility, also per the terms and conditions of the energy credit/renewable credit contract between the Customer and EEA

7. Functional Standards: Customer shall furnish, install, operate and maintain in good order and repair, all without cost to EEA, all equipment required for safe operation of the Facility in parallel with EEA's system. This equipment shall include, but not limited to equipment necessary to establish automatically and maintain synchronism with EEA's electric supply and a load break switching device that shall automatically disconnect the unit from EEA's supply in the event of overload or outage of EEA's supply. The Facility shall be designed to operate within allowable voltage variations of EEA's system. The Facility shall not cause any adverse effects upon the quality of

service provided to EEA's non-generating customers. Should the Facility be the cause of adverse impacts to the EEA system the Customer shall cease operation until the cause of the adverse impacts are corrected. The required corrections shall be made at the expense of the Customer.

8. Installation, Safe Operations and Maintenance: Except for metering equipment owned by EEA, all equipment on Customer's side of the point of delivery, including any required disconnect switch and synchronizing equipment, shall be provided, installed and maintained in satisfactory operating condition by the Customer, and shall remain the property and responsibility of the Customer. EEA shall bear no liability for Customer's equipment or for consequences of its operation or miss-operation. For purposes of gathering research data, EEA may at its expense install and operate additional metering and data gathering devices. The Customer shall be fully responsible to operate, maintain, and repair the Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

9. Access: Authorized EEA employees shall have the right to enter upon Customer's property at all times for the purposes of operating the disconnect switch and meters and making additional tests concerning the operation and accuracy of its meters. EEA shall provide reasonable notice to the Customer when possible prior to using its right of access

10. Assignment/Transfer of Ownership of the Facility: Customer may assign this Agreement to a new owner only upon receipt of the written consent of EEA.

11. Liability:
    a. EEA shall be liable for losses arising from personal injury, death, or property damage caused by the negligent or wrongful act or omission of EEA or its employees while performing activities under this Agreement, in accordance with applicable law.
    b. Customer shall be liable for losses arising from personal injury, death, or property damage caused by the negligent or wrongful act or omission of any employee of Customer while performing activities under this Agreement, in accordance with applicable law.
    c. In no event shall either Party be liable to the other Party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever.

12. Insurance:
    a. Customer, at its own expense, shall secure and maintain in effect during the term of this Agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $2,000,000 for each occurrence.
    b. EEA shall be named as an additional insured by endorsement to the insurance policy and the policy shall provide that written notice be given to the utility at least 30 days prior to any cancellation or reduction of any coverage. Such liability insurance shall provide, by endorsement to the policy, that the utility shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium of such insurance.
    c. EEA and Customer shall require their contractors and agents to maintain sufficient insurance to cover liabilities for any claim for personal injury, death or property damage caused by the contractors' and agents' activities under this Agreement.

13. Indemnification:
    a. Customer shall indemnify EEA for any and all losses it may incur to third parties as a result of Customer's negligent conduct or its breach of this Agreement.
    b. EEA shall indemnify Customer for any and all losses it may incur to third parties as a result of EEA's negligent conduct or its breach of this Agreement.

14. Mediation: If the Parties cannot resolve disputes arising under this Agreement informally, they agree to mediate the dispute. After the impasse, the Parties shall mutually agree within 15 days on a mediator and shall conduct the mediation as soon as reasonably possible. The Parties shall share all costs of such mediation. In the event the dispute cannot be settled through mediation, proper venue for any legal action shall be the Montezuma County District Court, Cortez, Colorado.

15. Governing Law: This Agreement shall be governed by the laws of the State of Colorado

16. Entire Agreement: This Agreement contains the entire interconnect agreement between Customer and EEA and may not be changed except by writing signed by both Customer and EEA.

In witness whereof, Empire Electric Association, Inc. and Customer have by their duly authorized representatives, executed this agreement in duplicate as of the day and year first above written.

14. Sample Renewable Energy Credit Contract

Energy Credit/Renewable Credit Contract

Empire Electric Association, Inc. and City of Cortez

This Contract is made and entered into this 26th day of May, 2009, by and between EMPIRE ELECTRIC ASSOCIATION, INC., 801 North Broadway, Cortez, Colorado ("Empire") and CITY OF CORTEZ ("Customer") 210 East Main Street, Cortez, Colorado, 81321 ("Customer Address"). Empire and the Customer may be referred to herein individually as a "party" or the "parties" to this Contract.

On the terms and subject to the conditions set forth in this Contract, the parties agree as follows:

1. **Power Purchased by Customer.** The Customer agrees to buy and Empire agrees to sell station service energy ancillary to the operation of a 240kW micro-hydroelectric power generation unit, connected to the electrical grid of Empire. The generation unit ("City Hydro Unit") is owned by the City of Cortez and is a part of its municipal water treatment system and located near the Customer's water treatment facility in Montezuma County northeast of Cortez, Colorado. Empire shall sell power for a monthly basic charge, as set forth in Empires large power tariff, of $191.25 and an energy charge, as set forth in Empire's small commercial tariff, of $0.10734 kWh. These tariffs may be changed from time to time by Empire.

2. **Credit Received by Customer.** Customer shall be entitled to receive a credit from Empire in an amount Empire receives from Tri-State Generation & Transmission, Inc ("Tri-State"), pursuant to its policy 115, as set forth in the chart attached hereto as Exhibit A and incorporated herein, for all energy generated by the City Hydro Unit for a term of ten (10) years beginning on the date of commercial startup on or before January 1, 2011 ("Commercial Startup Date") . The Commercial Startup Date will coincide with first day of the given month in which it is exercised. The City Hydro Unit shall conform to the interconnection agreement executed between the parties and attached to this Contract as Exhibit B, which Exhibit is herby incorporated by this reference into this Contract ("Interconnection Agreement"). Further, the City will be credited for energy produced during the testing phase of the project at a price of fifty percent (50%) of the contract energy price in Exhibit A. The City shall provide Empire 45 days of advance notice of project testing.

3. **Renewable Energy Credits.** The Customer agrees to sell and Empire agrees to purchase all of the Renewable Energy Credits ("RECs") generated by the City Hydro Unit for a term of ten (10) years beginning on the Commercial Startup Date. The price paid by Empire for the RECs shall be based on Empire's receipt of all RECs generated by the City Hydro Unit. The total price for the RECs shall be as shown on the attached Exhibit C. The amounts shown on the attached Exhibit C may be modified by the appropriate multipliers as set forth in the Colorado Renewable Portfolio Standards ("RPS"). The Customer shall be solely responsible for demonstrating compliance with the RPS standards in order to be able to apply appropriate multipliers. REC's will be paid on a semi-annual basis as mutually agreed, and at such time as Empire receives payment for the REC's from Tri-State, Empires wholesale supplier. In the event of non-payment by Empire, Customer has the right to cancel the Contract within 90 days.

4. **Representations.** Customer makes the following representations:

   a) Customer shall install the City Hydro Unit near the Customer's water treatment facility in Montezuma County northeast of Cortez, Colorado, on or before January 1, 2011;

b) Customer owns the City Hydro Unit and Customer's primary business is not the generation of electricity for retail or wholesale sale from the City Hydro Unit; and

c) Customer is authorized to enter into and sign this Contract and has read the Contract and agrees to be bound by its terms.

5. **Additional Terms and Conditions.** The parties further agree to the following terms and conditions:

a) Customer shall be solely responsible for ensuring that the City Hydro Unit equipment installed for this program meets all applicable codes, standards, and regulatory requirements.

b) The City Hydro Unit shall be a maximum capacity not to exceed 250 kilowatts, nameplate output capacity.

c) The term of this Contract shall be ten (10) years beginning on the Commercial Startup Date ("Term").

d) The City Hydro Unit shall be considered a fixture and attached to the land located near the Customer's water treatment facility in Montezuma County northeast of Cortez, Colorado. This Contract shall run with the land and be binding on any successor in interest or assign of the Customer, pursuant to section 4 (k) below. Empire shall purchase and own all RECs produced by the City Hydro Unit during the Term. Empire may record this Contract with the clerk and recorder's office of the county in which the City Hydro Unit is located, and the Contract shall constitute an encumbrance on the property on which the City Hydro Unit is located.

e) Empire shall make the payments to the Customer as set forth in Sections 2 and 3 above, per Tri-State policies 115 and 117, and their successor's policies.

f) Execution of this Contract by Empire does not imply any representation or warranty by Empire of the design, installation or operation of the City Hydro Unit equipment, and Empire expressly disclaims any and all warranties of the equipment as to workmanship, quality, or performance, including the fitness of the equipment for the purpose intended.

g) Empire shall not be responsible or liable for any claims made by suppliers or service providers for the City Hydro Unit, or for any personal injury or property damage caused by the City Hydro Unit or any individual component of the City Hydro Unit.

h) Empire Electric agrees to indemnify and hold harmless the City of Cortez, and its officers and its employees, from and against all liability, claims demands, and expenses, including Court costs and attorney's fees, on account of any injury, loss, or damage, which arise out

of or are in any manner connected with the purchase and sale of electric power under the terms of this Agreement, if such injury, loss, or damage is caused in whole or in part by, or is claimed to be caused in whole or in part by, the act, omission, or other fault of Empire Electric, any subcontractor of Empire Electric, or any officer or employee of Empire Electric.

The City of Cortez agrees to indemnify and hold harmless the Empire Electric, and its officers and its employees, from and against all liability, claims demands, and expenses, including Court costs and attorney's fees, on account of any injury, loss, or damage, which arise out of or are in any manner connected with the purchase and sale of electric power under the terms of this Agreement, if such injury, loss, or damage is caused in whole or in part by, or is claimed to be caused in whole or in part by, the act, omission, or other fault of The City of Cortez, any subcontractor of The City of Cortez, or any officer or employee of City of Cortez.

i) Customer shall maintain the City Hydro Unit and the individual components of the City Hydro Unit in good working order at all times during the Term. If during the Term the City Hydro Unit or any of the individual components of the City Hydro Unit should be damaged or destroyed, Customer shall promptly repair or replace the equipment to its original specifications, at Customer's sole expense.

j) This Contract shall be binding and enforceable against the parties, their successors and assigns, for as long as the Contract remains in effect Customer shall be prohibited, without the written consent of Empire, from selling, conveying, assigning or otherwise transferring the RECS to any other person during the term of the Contract while it owns the City Hydro Unit. In order for an assignment to be effective, Customer is required to provide to assignee copies of the following documents: this Contract, the Interconnection Application and any remaining warranty information. Upon assignment of this Contract, Customer shall remain liable for the obligations herein unless released in writing by Empire.

k) If any disputes arise concerning this Contract, including but not limited to enforcement of any term or condition of the Contract, the prevailing party in any action brought for the purpose of enforcing such provisions shall be entitled to recover its reasonable attorney fees, expenses and costs of such action from the non-prevailing party.

l) Failure of either party to enforce any term or condition of this Contract shall not constitute a waiver of that term or condition or of any other term or condition of this Contract. Any action shall be in the District Court located in Cortez CO.

m) The parties agree that a cause of action for breach of any provision of this Contract shall not accrue until the non-breaching party actually discovers the breach.

n) If any of the representations of the Customer, or Empire are false or incorrect, such false or incorrect representation shall, at Empire's discretion, constitute a material breach of

this Contract.

o) This Contract shall be governed by and interpreted in accordance with the laws of the State of Colorado.

p) This Contract may be executed in two or more counterparts, each of which is deemed original but all constitute one and the same instrument. The parties agree that a facsimile copy of a signature will be deemed original and binding.

q) This Contract serves as a bill of sale, transferring from Customer to Empire all of Customer's right, title and interest in and to the RECs associated with the City Hydro Unit. Customer warrants that it is transferring good title to all RECs associated with the City Hydro Unit to Empire. Customer warrants that all RECs transferred by Customer to Empire are free and clear from all liens, claims, security interests, encumbrances and other defects of title.

r) By executing this Contract, Customer grants permission to Empire to share with third parties the location of the City Hydro Unit and other information concerning the RECs sold to Empire by Customer under this Contract. Customer further allows Empire reasonable access to the property located at the City Hydro Unit for the purpose of ensuring that the City Hydro Unit is still functioning and in operation at all times relevant under this Contract subject to any state or federal security restrictions.

s) In the event any agreement between Empire and Tri-State regarding Tri-State's policies 115 and/or 117 is terminated or amended, and their successor Empire may elect to terminate or amend this Contract upon 90 days written notice to Customer. This Contract also shall be terminated and rendered null and void if the City has not placed the City Hydro Unit in commercial production by January 1, 2011.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed the day and year first above written.

Payment Schedule for Renewable Project Performance

($/MWh)
and
Renewable Performance Payment Calculation Example

Payment Schedule

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 and beyond
% of retail sales	1%	1%	1%	3%	3%	3%	3%	6%	6%	6%	6%	6%	10%
$ per MWh	$44.24	$44.24	$44.24	$14.97	$14.97	$14.97	$14.97	$8.50	$8.50	$8.50	$8.50	$8.50	$5.70

Example of Semi-Annual Billing Credit/Payment for Renewable Project Performance:

This example is intended for illustrative purposes only.

Assume the following Member Generation meter data for the period January – June of 2010:

Energy/Metered Generation:
550,060 kWh or 550.06 MWh

Renewable Performance Payment from Tri-State to Empire once attestation and verification listed in Section 7 has been received by Tri-State:

550.06 MWh * $44.24 per MWh = **$24,334.65**

Please note: example assumes that 1% compliance obligation of Empire exceeds amount listed in this example and assumes there is only a 1X resource multiplier effect.

Endnotes

[i] National Hydropower Association. *Why Small Hydro?* (http://www.hydro.org/why-hydro/)
[ii] Colorado Energy Office. *Small Hydroelectric Projects.* (http://www.colorado.gov/cs/Satellite/GovEnergyOffice/CBON/1251599988450)
[iii] For additional information see www.lowimpacthydro.org
[iv] Renewable Resource Generation Development Areas Task Force. *Connecting Colorado's Renewable Resources to the Markets.* December, 2007. p 16.
[v] Based on the EPA's 2009 estimate that the average home uses 11,319 kWh a year. (http://www.epa.gov/cleanenergy/energy-resources/refs.html)
[vi] Colorado Governor's Energy Office. Prepared by Navigant Consulting. *2010 Colorado Utilities Report.* August 2010, p 1.
[vii] DSIRE. Colorado Incentives/Policies For Renewable and Efficiencies. (http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO26R&re=0&ee=0
[viii] FERC has developed handbooks designed to help developers and others identify and understand relevant sections of FERC regulations:
Handbook for Hydroelectric Project Licensing and 5 MW Exemptions from Licensing ("Licensing Handbook"). FERC's Licensing Handbook, issued in 2004, includes detailed explanations of eligibility and requirements associated with the federal licensing process for hydroelectric facilities. It also includes helpful citations and parts of the Federal Power Act, which granted FERC the authority to license non-federal hydroelectric projects.
Hydroelectric Project Handbook for Filings Other Than Licenses and Exemptions. Issued by FERC in 2001, this handbook includes detailed information on how to obtain a Conduit Exemption.
[ix] FERC, Handbook for Hydroelectric Project Licensing and 5 MW Exemptions from Licensing, April 2004, p. 2-1; Federal Power Act, Section 4(e).
[x] Energy Trust of Oregon. Volume One, 3.
[xi] Energy Trust of Oregon. Volume One, 4.
[xii] 18 CFR 4.30 (b)(2).
[xiii] Energy Trust of Oregon. Volume One, 7
[xiv] Energy Trust of Oregon. Volume Two, 4.
[xv] Energy Trust of Oregon. Volume Two, 12-14.
[xvi] Energy Trust of Oregon. Volume Two, 14-17.