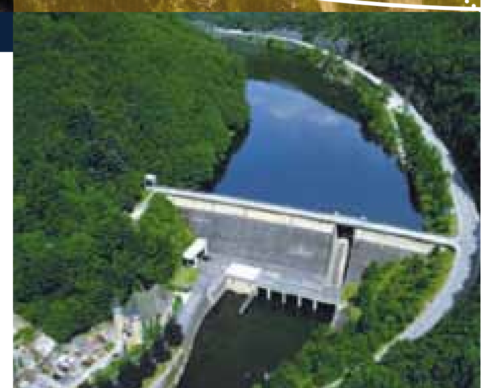

Hydroelectric Power

A Guide for Developers and Investors

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Foreword

Hydropower has a well-established role in the energy sector and support for further development of this energy resource is very important, especially in developing countries. Hydropower is a vital renewable energy resource and for many countries it is the only renewable energy that has the potential to expand access to electricity to large populations. Yet it remains underdeveloped in many countries, especially in Africa, where less than 10 percent of hydropower potential has been tapped.

The opportunities are great. But hydropower development poses complex challenges and risks. While large storage hydro may offer the broadest benefits to society, it also tends to present the biggest risks. Creation of reservoirs sometimes means resettlement of whole communities, the flooding of large areas of land, and significant changes to river ecosystems.

As presented in the publication "Toward a sustainable energy future for all: directions for the World Bank Group's energy sector," the World Bank Group is firmly committed to the responsible development of hydropower projects of all sizes and types—run of the river, pumped storage, and reservoir—including off-grid projects meeting decentralized rural needs. The IFC has approved 42 hydropower projects totaling more than US$1.3 billion over the last decade.

This guidebook is intended for use by IFC and World Bank clients and stakeholders planning and implementing hydro projects; it is not intended to replace official guidance documents of the World Bank Group, but instead is an effort to capture the knowledge and experience gained through the extensive engagement of IFC staff and our clients in hydropower development.

This guide covers all aspects of hydropower project development, emphasizing the importance of interactions among technical, commercial, permitting/licensing, environmental and social, and financing activities. The technical sections are more detailed and can be used as reference, while the permitting/licensing and financing sections are intended more as a high-level review.

We hope that the knowledge presented here helps to support the sustainable and well-executed development of valuable hydropower resources to meet the increasing demand for clean, reliable, affordable energy.

Mary Porter Peschka

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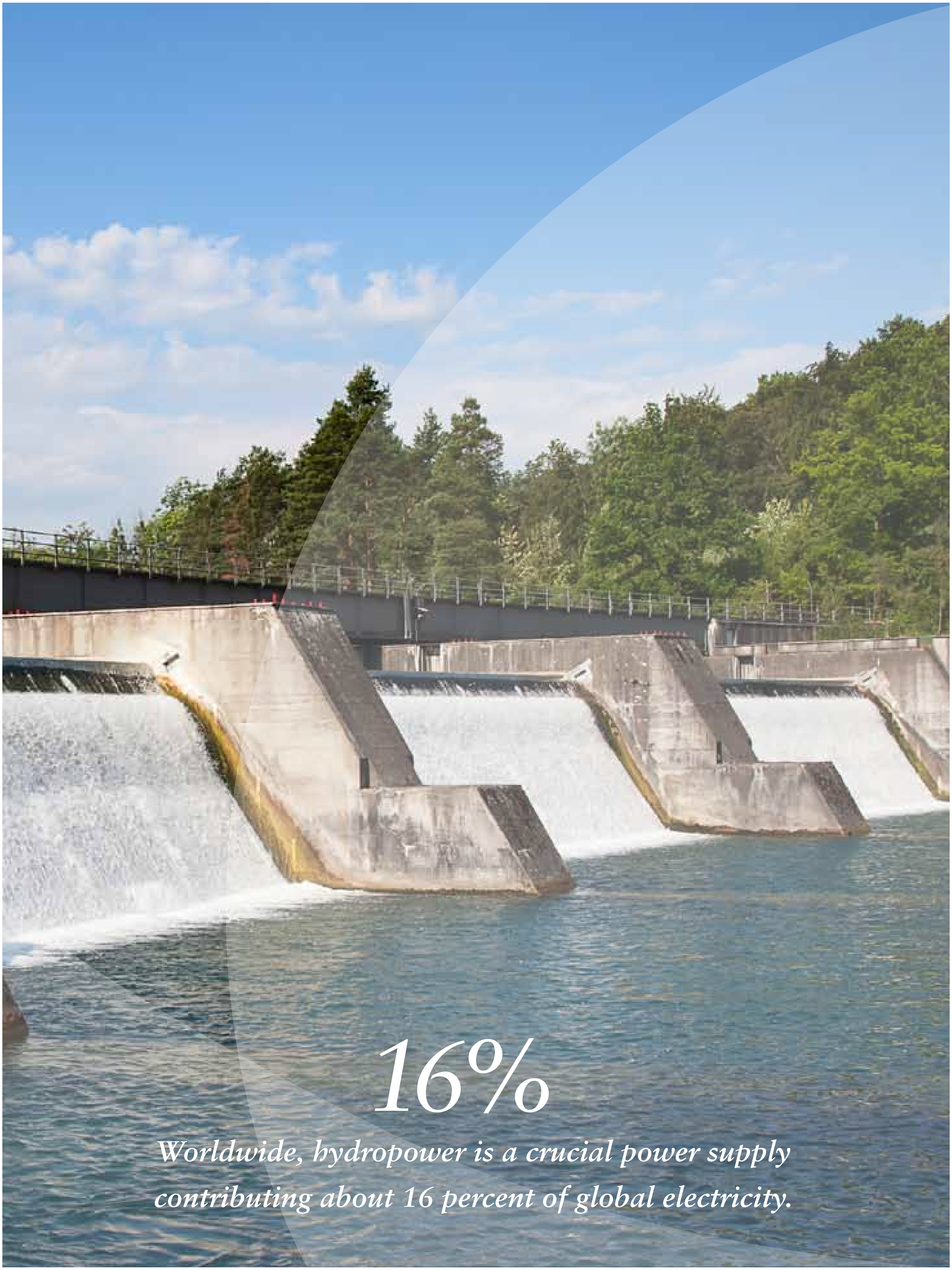

16%
Worldwide, hydropower is a crucial power supply contributing about 16 percent of global electricity.

1

Executive Summary

Worldwide, hydropower is a crucial power supply option for several reasons. First, it is a renewable energy resource that can contribute to sustainable development by generating local, typically inexpensive power. Second, hydropower reduces reliance on imported fuels that carry the risks of price volatility, supply uncertainty and foreign currency requirements. Third, hydro systems can offer multiple co-benefits including water storage for drinking and irrigation, drought-preparedness, flood control protection, aquaculture and recreational opportunities, among others. Finally, hydro can allow more renewables—especially wind and solar—to be added to the system by providing rapid-response power when intermittent sources are off-line, and pumped energy storage when such sources are generating excess power.

Hydropower contributes about 16 percent of global electricity, a share that is expected to grow. Hydro's technical potential is five times the current utilization rate, and huge potential exists in developing countries. According to U.S. Energy Information Administration (EIA) projections, hydro can contribute up to 16,400 TWh/yr, and by 2050 total installed hydropower capacity will double (1,947 GW), generating an annual 7,100 TWh [EIA 2010]. Most mid-sized and large hydro resources in developed countries have been exploited but opportunities for additional rational utilization of small hydropower plants exist in all countries, especially in the developing world. Sub-Saharan Africa, where the energy access deficit is largest, has over 400 gigawatts of undeveloped hydro potential—enough to quadruple the continent's existing installed capacity of 80 GW.

It is expected that the role of hydropower will continue to expand, especially in developing countries. IFC commissioned this guide to collect knowledge and build capacity of those engaged in the complete hydro project development cycle from project inception to operation. This guide covers all types and sizes of hydropower projects—run-of-river, storage and pumped storage—and small, medium and large hydropower plants. The guide discusses each step of a hydropower project—site selection, plant design, permitting/licensing, financing, contracting and commissioning, and explains key issues and typical responses.

The guide aims to assist all players in hydropower development involved in project planning, evaluation (appraisal), implementation and monitoring.

Hydropower plants (HPPs) are unique compared to other power supply options such as thermal. HPPs are always custom-designed site-specific projects. HPPs require substantial capital investment, but they offer extremely low operating costs and long operating lifespans of 40–50 years that can often be extended to 100 years with some rehabilitation. The result is extremely competitive production costs for electricity.

However, developing a hydro project is usually a challenge. There are substantial uncertainties associated with hydrology (which impacts power generation and revenues) and geology (which may substantially increase construction costs). Site licenses and permits could be difficult to obtain as many stakeholders are involved, often with conflicting rights and responsibilities. Construction in remote areas is difficult to plan and estimate the costs. Environmental and/or social risks can be complex to understand and manage and may introduce reputational risks for the developer and financiers. Finally, revenue (impacted by both the amount of energy generated and the tariff the power market is able to pay) is uncertain.

For these reasons, HPP project planning and implementation must be comprehensive and well-coordinated from inception to commissioning. Figure 1-1 shows a typical development process from the perspectives of the project developer and financier. Key decisions such as site selection, HPP plant design, permitting/licensing and financing must consider important factors such as hydrology, topography, geology, social and environmental impacts, and future potential uses of the

40-50 years | HPPs offer extremely low operating costs and long operating lifespans of 40-50 years that can often be extended to 100 years with some rehabilitation. The result is competitive production costs for electricity.

water, for irrigation or upstream HPPs for example. Additional questions to be considered include the following: What role would the proposed HPP project play in the power market? Does the power market require additional capacity or energy and when? What level of tariff can be expected? How much revenue will the HPP generate? Who are the key stakeholders and how will they be affected? How will public consultation and participation be carried out throughout planning and implementation phases to sustain key stakeholder support and contribute to on-time project completion?

Figure 1-1: HPP project development process

BANK PERSPECTIVE	MAIN ACTIVITIES (DEVELOPER)
PHASE 1	SITE IDENTIFICATION / CONCEPT
	□ Identification of potential site(s) □ Funding of project development □ Development of rough technical concept
PHASE 2	PRE-FEASIBILITY STUDY
	□ Assessment of different technical options □ Approximate cost/benefits □ Permitting needs □ Market assessment
PHASE 3	FEASIBILITY STUDY*
□ First contact with project developer	□ Technical and financial evaluation of preferred option □ Assessment of financing options □ Initiation of permitting process
PHASE 4	FINANCING/CONTRACTS*
□ Due diligence □ Financing concept	□ Permitting □ Contracting strategy □ Supplier selection and contract negotiation □ Financing of project
PHASE 5	DETAILED DESIGN*
□ Loan agreement	□ Preparation of detailed design for all relevant lots □ Preparation of project implementation schedule □ Finalization of permitting process
PHASE 6	CONSTRUCTION*
□ Independent review of construction	□ Construction supervision
PHASE 7	COMMISSIONING*
□ Independent review of commissioning	□ Performance testing □ Preparation of as build design (if required)

**Involvement of financing institution begins with Phase 3.*
Source: FICHTNER

Site selection is the first step. In developing countries, information on potential HPP sites, especially for small HPPs, may be unavailable or unreliable and out of date, unlike developed countries where most potential sites for medium and large hydropower plants are already well known. Conditions surrounding HPPs are subject to changes, not only the power tariffs or the power market structure, but also the social and environmental characteristics, all of which can affect the attractiveness of potential sites. As such, sites that were unattractive in the past may become attractive in the future and vice versa.

Good hydrological data are essential to select an HPP site and develop the optimum plant design. Typically, hydrological data for at least 15 years are required and should include not only the amount of water (flow rate) but also annual distribution.

Pre-feasibility (pre-FS) and feasibility (FS) studies are conducted to confirm site attractiveness, develop a preliminary plant design, estimate investment requirements, establish the next steps for project implementation (including project schedule) and prepare the project for financing. Also, pre-FS and FS identify potential project risks and opportunities to mitigate them by optimizing key project parameters, including plant design and output. Project technical features are determined by site-specific conditions:

- How much storage should the HPP have? Storage capacity is determined by the total amount of water available, water seasonality, power market needs and specific geological and topographic conditions that allow reservoir construction. If storage is not feasible or not required, HPPs can be designed as run-of-river plants.
- What is the appropriate and optimum head? This is crucial because head choice determines plant capacity (MW) and affects turbine selection.

Permitting and licensing is often a complicated process requiring multiple approvals from many central and local government agencies. Water rights, land acquisition and site access are among the key elements that must be checked from both legal and practical points of view. Project success depends on buy-in and support from local municipalities, which requires stakeholder consultation and two-way communication throughout the entire HPP development process, beginning with the planning phase. Local concerns should be assessed and mitigation strategies should be developed and in place.

In parallel and equally important, environmental and social assessments must be carried out because impacts can be substantial, and not only when HPP projects include large dams. Mitigation strategies should be developed and implemented. Commonly accepted international standards that have been developed for detailed environmental and social assessment of private sector projects include, amongst others, the IFC Performance Standards, which are discussed later in this guide. The Performance Standards in turn form the basis of the Equator Principles, a voluntary approach to environmental and social risk management adopted by many financial institutions.

The approach to contracting can vary but typically a project is divided into three to four contracts in the following categories:

- Civil works
- Electrical and mechanical (E&M) equipment

- Grid connection
- Penstock (often included in civil works)

For each of the above, it is common to tender and sign an engineering, procurement and construction (EPC) contract. Under an EPC contract, the contractor designs the HPP, procures materials and builds the project, either directly or through subcontracts. Typically the contractor carries project schedule and budget risks in return for a fixed-price lump sum, for which 10-30 percent down payment is required; 10-20 percent is typical withholding, which is to be paid upon successful plant completion and acceptance. Usually, the owner's engineer supervises and monitors the project, sometimes along with an engineer hired by the financier
(unless the developer has the capacity to supervise/monitor the project).

The critical path items for hydropower projects are: access roads, penstock construction, tunneling, E&M equipment manufacturing, and grid connection.

Table 1-1 provides a rough idea of typical HPP costs, even though HPP costs are site-specific and can vary widely. Most large greenfield projects range from US$1000/kW to US$3500/kW. Small HPPs have higher investment costs—US$1300/kW to US$8000/kW.

Table 1-1: Typical HPP costs

Technology	Installed costs (US$/kW)	Operations and maintenance costs (%/year of installed costs)	Capacity factor (%)	Levelized cost of electricity (LCOE) (2010 US$/kWh)
Large hydro	1,050–7,650	2–2.5	25 to 90	0.02–0.19
Small hydro	1,300–8,000	1–4	20 to 95	0.02–0.27
Refurbishment/ upgrade	500–1,000	1–6		0.01–0.05

Source: FICHTNER

Annual O&M costs range from 1.0–4.0 percent of investment costs. The IEA assumes 2.2 percent for large HPP and 2.2–3 percent for small HPP. However, these figures do not include major electro-mechanical equipment replacement, which would be required a couple of times during the HPP lifespan and would raise average O&M costs to US$45/kW/year for large HPP; US$52/kW/year for small HPP.

Considering the above costs and the capacity factor (affected by hydrology), HPP electricity generation costs range between US$0.02/kWh and US$0.085/kWh; the lower costs are for refurbishing/upgrading existing HPPs.

Financing HPPs can be challenging because all the investment is required up front and most benefits are realized over the project's long operating lifespan. Inherent to each HPP project are uncertainties that add complications to financing challenges. For example, hydrology determines water flow amounts, which determines the amount of energy produced. But hydrology depends on annual weather conditions, which can vary widely. Also, medium and large HPPs can include high construction risks, a prolonged project implementation schedule (e.g., 10 years) and schedule delays due to the nature of building in remote locations, delays due to permitting and licensing, local opposition to the project, or adverse weather conditions. Consequently, investors must assess all risks and ensure that they are covered. These include not only hydrology but also sedimentation, permitting and licensing, political risks, payment default, local currency devaluation, local domestic tariff affordability, cost overruns, and power market changes. For example, a debt-service coverage ratio (DSCR) greater than one must be ensured under the worst-case hydrology scenario such as dry years.

HPPs can be financed by private corporate entities (balance-sheet financing) or project finance. Also common are public-private-partnership (PPP) schemes because HPP benefits are multipurpose and include externalities that private investors find difficult to capture. Regardless of the source, financing must be long-tenor and must be covered with long-term off-take power-purchase agreements.

Hydro project development checklist

During the project planning process, some items must be checked multiple times with increasing attention to finer details of each aspect when moving through each phase. This guide assumes that the planning process has three phases—initial screening, screening, and due diligence. Table 1-2 below indicates the main area of assessment and data requirements for each phase. Although not every financing process follows this structure, due diligence is a precondition for every financing decision.

For a comprehensive checklist (including potential risks) to maximize project success from the perspectives of a financing institution and project developer, please see Section 17/Annex, Table 17.1.

Table 1-2: HPP requirements during the project cycle

Phase	Check by bank	Data/study requirements
1. Initial screening	Check plausibility of main project parameters; check developer financial standing/ integrity	Project data sheet or pre-feasibility study (PFS) Financial statements Basic information about developer
2. Screening	Check technical/ economic project feasibility Check status of permits and licenses Check for completeness of required documentation for Phase 3	Minimum pre-feasibility for technical/economic check; better feasibility study Information about permits and licenses obtained/outstanding Other studies, in case of PFS gaps
3. Due diligence	Detailed technical, environmental and social, financial, legal due diligence of project	Minimum feasibility study (FS) Information about permits and licenses obtained/outstanding Other design documents in case of FS gaps Supplier price quotations

Source: FICHTNER

This guide aims to provide a comprehensive overview of all stages of hydropower development, and highlight hydropower's unique characteristics compared with other power generation options.

Introduction 2

Water is the most important natural resource for all living species. The origin of civilization is closely interconnected with water use and throughout history humans have developed technologies to exploit water for use in agriculture, households, transport, recreation, industry, and energy production. This guide focuses on the role of water as an energy resource.

Worldwide, hydro is an important source of sustainable power supply and its role is expected to increase, especially in developing countries. As a result, IFC commissioned this guide to enhance understanding of the complete project development cycle, from inception to commissioning and operation. The guide explains each step of the project development process, including common challenges that must be addressed to ensure a successful project. The guide is intended for use by key stakeholders who are involved in hydropower project (HPP) planning, evaluation (appraisal) or monitoring.

The guide aims to provide a comprehensive overview of all stages of hydropower development, and highlight hydropower's unique characteristics compared with other power generation options. The guide describes a range of sizes and designs for hydropower facilities, and offers guidance on key issues during site selection, plant design, permitting/licensing, financing, contracting and commissioning. Some key issues are hydrology, social and environmental context, permits and licensing, political risk, off-taker creditworthiness, currency fluctuations, and power sector sustainability, among others.

The guide covers all types and sizes of HPPs—run-of-river, storage, and pumped storage—and micro to large. Although the guide includes substantial technical information, it is intended as a reference for a non-technical audience. Sources for additional information are included.

Throughout the guide, project case studies are used to illustrate specific situations encountered in hydropower project development; the case studies include a range of plant sizes and technology types.

The guide comprises three main sections: Technical, Project Development and Finance (see Box 2-1).

Technical topics include the following sections:

- Overview of hydropower development *(**Section 3**)*
- HPP design and typical layouts *(**Section 4**)*
- Site selection *(**Section 6**)*
- Hydrology and energy calculations *(**Section 7**)*

Project development phases include the following:

- HPP project development *(**Section 5**)*
- Permits and licensing *(**Section 8**)*
- Construction *(**Section 9**)*
- Commissioning *(**Section 10**)*
- Operation and maintenance *(**Section 11**)*

Environmental and economic discussion includes the following:

- Environmental and social impacts *(**Section 12**)*
- Capital and O&M costs *(**Section 13**)*
- Economic and financial analyses *(**Section 14**)*
- Financing HPP projects *(**Section 15**)*

Section 17 Annex has a comprehensive list of risks and mitigation options.

Box 2-1: Information in the HPP guide

TECHNICAL	PROJECT PHASES	ENVIRONMENTAL AND ECONOMIC
• Types of HPP and the water resource: energy generation through water, hydroelectricity, types of hydro projects, what are small, medium and large projects • Design and typical layout: types of hydropower schemes, main site layouts, civil structures, hydraulic steel structures, grid connection, ecology, optimization of parameters, layouts. • Site selection: basic data requirements, constraints. • Hydrology and energy calculations: hydrological considerations, power and energy, energy yield predictions, seasonal variability, load factor, uncertanties, losses.	• Project development: overview of project phases, description, pre-feasibility/feasibility phase, timelines, project structures. • Permits and licensing: general considerations, performance standards, typical requirements. • Construction: contracts, scheduling, phases, planning, task sequencing, stakeholder/risk/cost management. • Commissioning: main criteria, testing phases. • Operation & maintenance: scheduled/unscheduled maintenance, performance monitoring, contracts, procedures.	• Environmental and social impact mitigation: Equator Principles. • Capital and O&M costs: typical CAPEX components, benchmarks, OPEX structures (fixed and variable) including benchmarks. • Economics and financial analysis: benefits and costs, assumptions, financial modeling results, sensitivity analyses. • Financing HPP projects: HPP finance process, financing alternatives, project evaluation, risks

Source: FICHTNER

Estimated global technical potential for hydroelectricity is 16,400 TWh/yr according to the U.S. Energy Information Administration (2010).

Overview of Hydropower Development

3

This chapter describes transformations that occur when the energy stored in water is harvested; it provides a short historical review of how hydropower technology has evolved; it discusses the future of hydropower; it lists factors that might inhibit hydropower development.

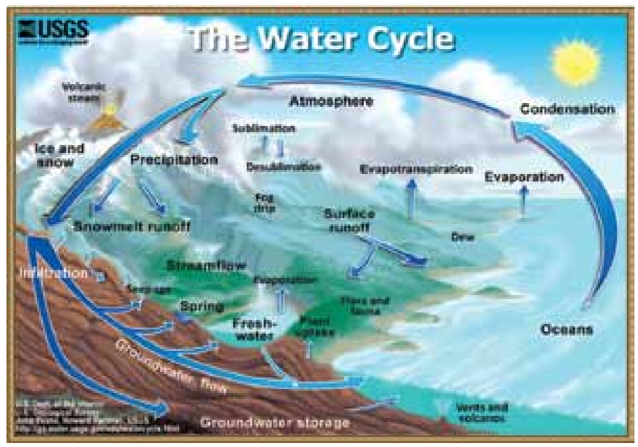
3.1 Energy conversion: from water to power

Hydropower is considered a renewable form of energy because it is based on solar energy that drives the hydrologic cycle (see Figure 3-1). The hydrologic cycle refers to the following process: the sun heats water (about 97 percent from oceans); water evaporates; rising air currents transport water vapour to the upper atmosphere where lower temperatures condense vapour into clouds. Air currents move the clouds around the globe and eventually, water falls as precipitation. Through this process, water can reach altitudes higher than sea level.

Gravity causes water to descend from higher elevations creating opportunities to harness water energy—gravitational energy from falling water and kinetic energy from flowing water. The amount of kinetic energy available from water flow depends on the height from which the water drops, the angle of the slope, and the volume of water per unit of time, i.e., the discharge.

The energy of flowing water is harnessed by turbines, which are placed in the path of the water flow. The force exerted by water moving over turbine blades rotates the turbine runner; the turbine runner rotates the generator, which produces electricity.

Figure 3-1: The water cycle



Source: United States Geological Survey

3.2 Hydropower potential

Hydropower's *theoretical potential* includes the total potential energy from all water resources within specified spatial boundaries without any physical, technical and economic usage limitations. In practice, only a small percentage of theoretical potential can be harvested.

Hydropower's *technical potential* is defined as the total energy that can be generated under the technical, infrastructural and ecological constraints. Usually, technical potential ranges from 20 to 35 percent of theoretical potential [Auer 2010].

Technical potential is lower than theoretical potential because technical restrictions limit, for example, using flood flows for energy production, unless a reservoir with large storage capacity is available, which is not always the case. Therefore, a large proportion of surface runoff remains unexploited for energy production. Another factor that reduces available technical potential when ecological restrictions are considered is providing a minimum flow to preserve ecologically and socially motivated minimum water conditions. This may reduce the stream flow that can be diverted from the main river for energy production.

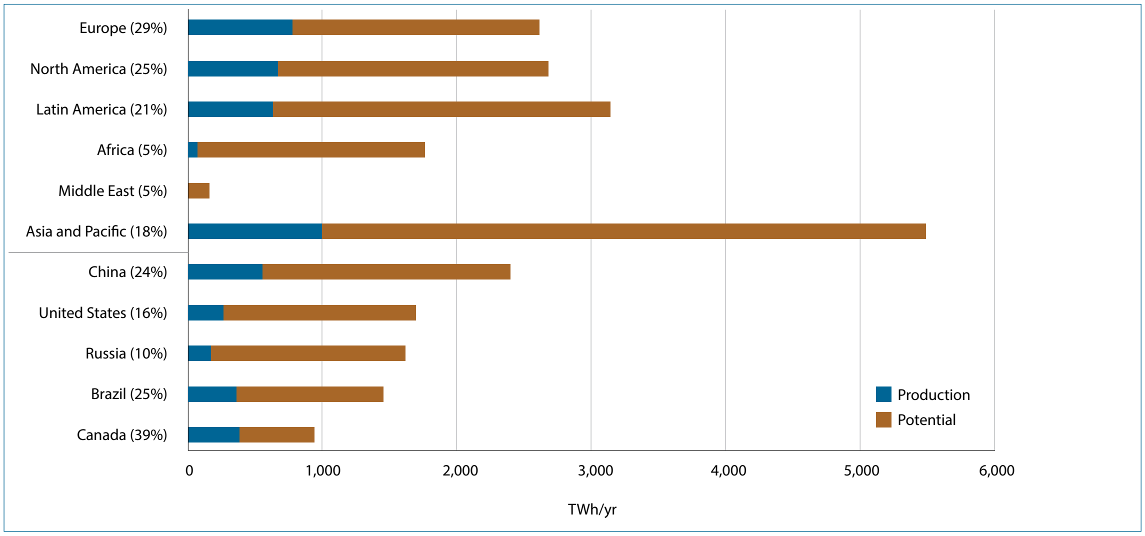
Estimated global technical potential for hydroelectricity is 16,400 TWh/yr according to the U.S. Energy Information Administration (2010). The EIA technological roadmap for hydropower notes that technical potential corresponds to about 35 percent of theoretical potential.

Hydropower's *economic potential* is defined as the energy capacity that is economically exploitable relative to alternative energy forms.

Current hydropower production and unexploited resources for the regions of the world and for the five countries with the highest technical potential are shown in Figure 3-2 below. Asia has by far the largest hydropower technical potential, followed by Latin America and North America. China has the highest existing energy generation and uses 24 percent of its potential.

Further information on hydropower potential types can be found in H. B. Horlacher, 2003, Globale Potenziale der Wasserkraft.

Figure 3-2: Current hydroelectricity production and available technical potential



Source: WEC Survey of Energy Resources 2007, IEA Renewables Information 2010 (2008 data).

3.3 Brief history of hydropower development

The mechanical energy of water has been harnessed for production since ancient times. Early uses included irrigation, grinding grain, sawing wood and manufacturing textiles, among others. Water current energy was converted by water wheels into useful forms of power; the invention of the water wheel dates to 3rd Century BC. During the industrial revolution hydro turbines gradually replaced waterwheels because turbines could exploit head much larger than their diameter and offered significantly higher efficiencies.

Using hydropower for electricity generation dates to 19th C., making it the first renewable energy source to produce electric power. Today it remains the most common form of renewable energy and plays an important role in electric power generation worldwide (see Table 3-1). For a brief overview of technology development from ancient to modern times see Box 3-1.

3.4 Advantages and disadvantages of hydropower

Compared with other technologies, the most important advantages of hydropower are the following:

- Hydropower generation is based on a reliable proven technology that has been around for more than a century and hydropower plants can be easily rehabilitated or upgraded utilizing recent advances in hydro technologies.
- Hydropower generation is renewable because it does not reduce the water resources it uses and does not require fuel.
- In most cases, hydropower is an economically competitive renewable source of energy. The levelized cost of electricity (LCOE) is usually in the range of US$0.05 to US$0.10 per kWh [EIA 2010]. Rehabilitating or upgrading existing hydropower schemes provides opportunities for cost-effective capacity increases.
- Hydropower exploits domestic water resources, thereby achieving price stability by avoiding market fluctuations.
- Storage hydropower schemes (dams, pumped storage) offer operational flexibility because they can be easily ramped up or shut down, creating potential for immediate response to fluctuations in electricity demand. Thus storage hydros are valuable to meet peak demand or to compensate for other plants in the grid (especially solar and wind), which can experience sudden fluctuations in power output.
- The creation of reservoirs also allows water to be stored for drinking or irrigation, reducing human vulnerability to droughts. Reservoirs can provide flood protection, and can improve waterway transport capacity. Further, HPPs with reservoirs can generate energy during dry periods and regulate fluctuations in the energy supply network by using the stored water.
- Environmental impacts triggered by implementing hydropower schemes are well known and manageable.

Disadvantages of hydropower include the following:

- High up-front investment costs compared to other technologies, such as thermal power (but low operational costs since no fuel is required).
- Reservoirs may have a negative impact on the inundated area, damage river flora and fauna, or disrupt river uses such as navigation. However, most negative impacts can be mitigated through project design. The IFC and other multilateral financial institutions have strict mandatory requirements for assessment and mitigation of social and environmental impacts.

For more information, refer to the IFC Performance Standards on Environmental and Social Sustainability or the IFC Environmental, Health and Safety Guidelines for construction works and transmission lines.[1]

1. Full references for the IFC Performance Standards and EHS Guidelines are provided in Section 16, References.

Box 3-1: From ancient to modern times

- The Archimedes Screw is a machine used in the ancient years for lifting water to a higher level usually for irrigation purposes. It was named after the famous scientist when he used it for removing water from the hold of a large ship.

Figure 3-3: Egyptian terracotta figurine (about 30 BC) showing a man driving an Archimedes screw as a treadmill.

Source: British Museum, Department of Egyptian Antiquities, No. EA-37563, London, England.

- The machine consisted of a circular pipe enclosing a helix that is inclined at an angle of about 45 degrees to the horizontal. Its lower end was in the water. The rotation of the device caused the water to rise in the pipe.

- Archimedes' screw is now used as hydropower turbine. The principle remains the same as in the ancient device but it acts in reverse. The main difference is that water is poured into the top, thus forcing the screw to rotate. The rotating shaft is able to drive an electric generator for electricity production. The screw turbines consist of helices rotating in open inclined troughs.

- This installation has the same benefits as using the screw for pumping. It is able to handle very dirty water and a wide range of discharges with high efficiency. They can work on heads as low as 1.5 m. Such turbines can produce as little as 5 kW, and the largest 500 kW.

Figure 3-4: Installation of Archimedes screw turbine in the River Wandle, at Morden Hall Park, south London.

Source: The Guardian

3.5 Global hydropower statistics

The figures given below are derived from reports published by International Energy Association (IEA), International Hydropower Association (IHA) and Worldwatch Institute [Kumar 2012].

3.5.1 Current global situation

Global energy generation and installed capacity

- Hydropower generation has increased by 50 percent since 1990. The highest absolute growth was observed in China.
- In 2008, hydropower was the most common renewable energy with a production of 3,288 TWh worldwide, corresponding to 17.3 percent of global electricity production. In 2010, hydro production increased to 3,427 TWh [IHA 2013].
- Worldwide installed hydropower capacity reached 985 GW in 2012. In the same year, pump storage capacity was 130 GW [IHA 2013]. Hence, in 2012 total installed hydropower capacity was 1115 GW.
- 27–30 GW of hydropower and 2–3 GW of pump storage were commissioned in 2012 [IHA 2013]; about half of new capacity was installed in China (Figure 3-5).
- In 2010, hydropower was generated in 150 countries; 32 percent of global hydropower was generated in the Asia-Pacific region. China is the leading hydropower producer, with 721 TWh in 2010. [Kumar 2012]

Table 3-1: Historic developments in hydropower generation technology.

Year	Development
mid-1770s	Bernard Forest de Bélidor publishes Architecture Hydraulique. This four-volume work described vertical- and horizontal-axis hydraulic machines
1849	James B. Francis develops a radial-flow turbine whereby water flows from the outer circumference towards the center of runner, improving on the design of the existing inward-flow reaction turbine. The radial-flow was the first modern turbine and it had an efficiency of over 90 percent.
1879	Lester Pelton develops a turbine based on a double bucket design, which exhausted the water to the side.
1879	Thomas Edison demonstrates incandescent lamp in New Jersey
1881	Construction of Niagara Falls hydroelectric power site. It is the first hydropower facility developed for major generation. Direct current station built to power arc and incandescent lighting.
1882	Construction of Vulcan Street hydroelectric power plant, in Appleton, Wisconsin, with an output of about 12.5 kilowatts of alternating current. Coupling of electric generator to the turbine.
1913	Viktor Kaplan develops a propeller-type machine. It is an evolution of the Francis turbine that allows the development of low-head hydro sites.

Source: FICHTNER

GHG Emissions reduction
Hydropower generation at present production levels prevents GHG emissions equivalent to burning 4.4 million barrels of petroleum per day worldwide [USGS 2014].

3.5.2 Future outlook

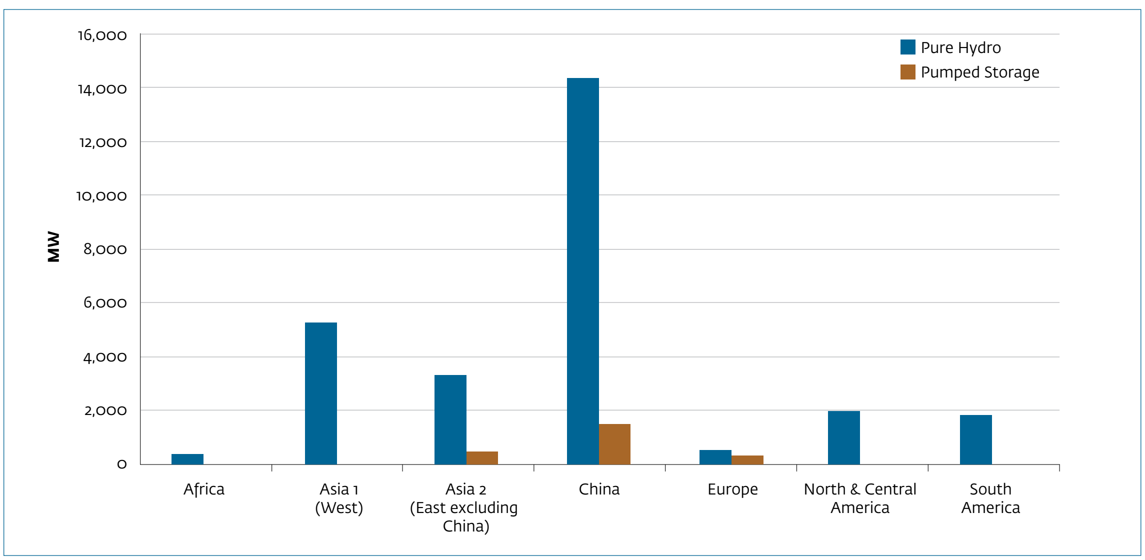
In the short term, estimated total installed capacity will be 1,300 GW by 2017 (Figure 3-6). This refers to commissioned HPP schemes and capacities that are under construction [IEA 2012b].

Installed hydropower capacity is projected to reach 1,947 GW by 2050, i.e., about double current levels. [IEA 2012c]. Hydropower generation will almost double to 7,100 TWh per year. These estimates are based on the 2°C Scenario of the IEA Energy Technology Perspectives 2012 (ETP 2DS), according to which combined energy sectors will achieve the goal of reducing annual CO_2 emissions to half of 2009 levels (Figure 3-7).

According to the BLUE scenario of IEA publication, Energy Technology Perspectives 2010, which targets a 50 percent reduction in energy-related CO_2 emissions by 2050, annual hydroelectricity generation could be increased by up to 6,000 TWh by 2050.

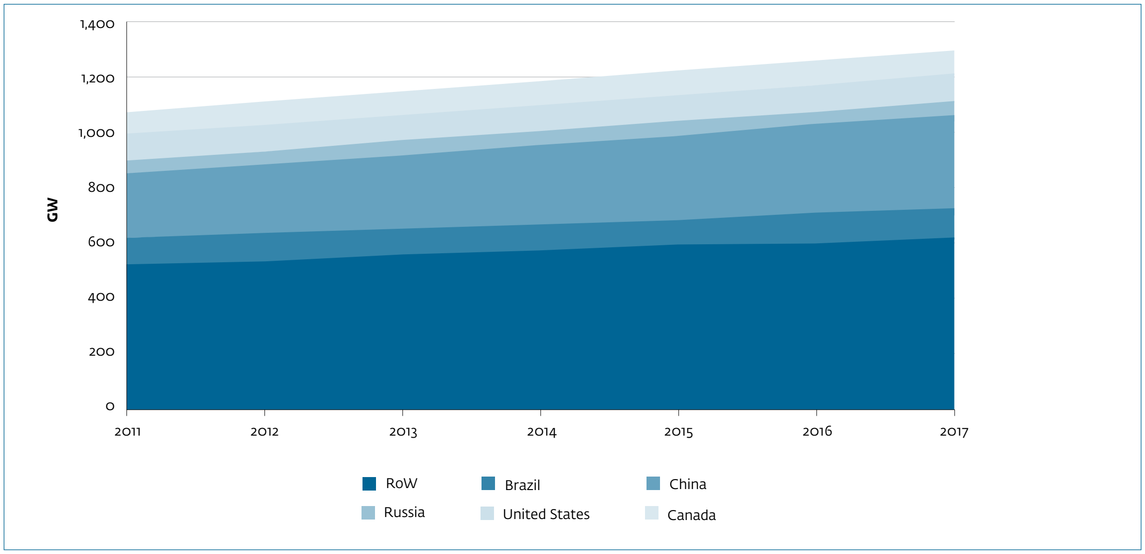
Current global capacity of pumped-hydro storage could increase ten-fold as some existing hydropower plants could be transformed into pumped-hydro storage plants.

Figure 3-5: Estimate of commissioned capacity in 2012



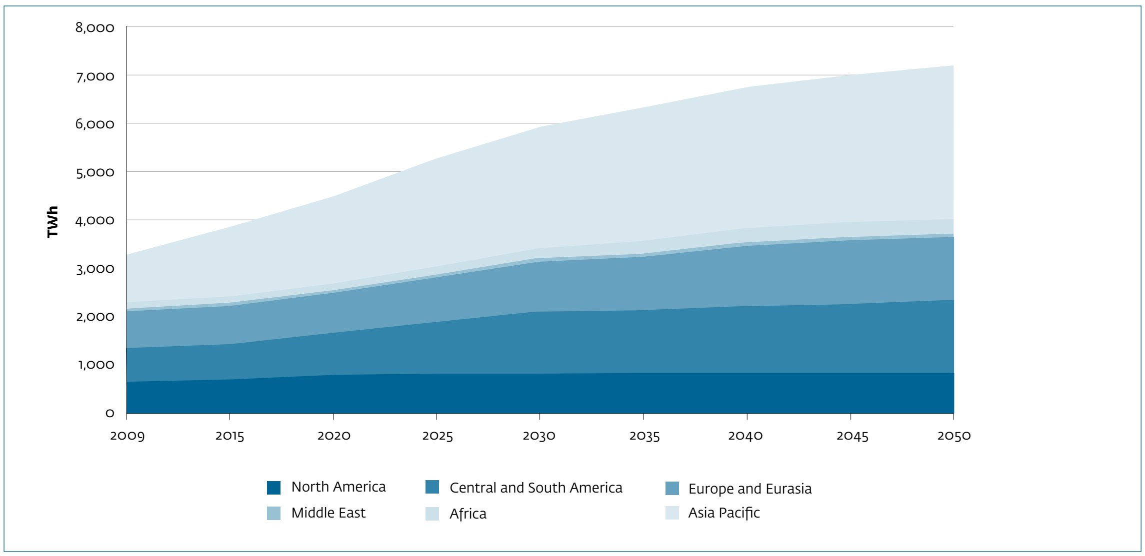
Sources: IHA 2013 and FICHTNER

Figure 3-6: Expected mid-term evolution of hydropower installed capacity



Sources: International Energy Agency, 2012, Technology Roadmap, Hydropower; and FICHTNER

Figure 3-7: Hydroelectricity generation until 2050 in the Hydropower Roadmap vision (IEA)



Sources: International Energy Agency, 2012, Technology Roadmap, Hydropower and FICHTNER

This chapter provides an overview of hydropower design schemes; it classifies hydropower plant types and describes main types of site layouts.

4 Design and Typical Layouts

Each hydropower plant is custom-designed, a one-off project that aims to achieve optimal power plant flow conditions. Consequently, each plant is precisely designed and constructed to respond to its surrounding topography, existing hydrological regime, prevailing environmental and social (E&S) constraints, and existing infrastructure, among other boundary conditions.

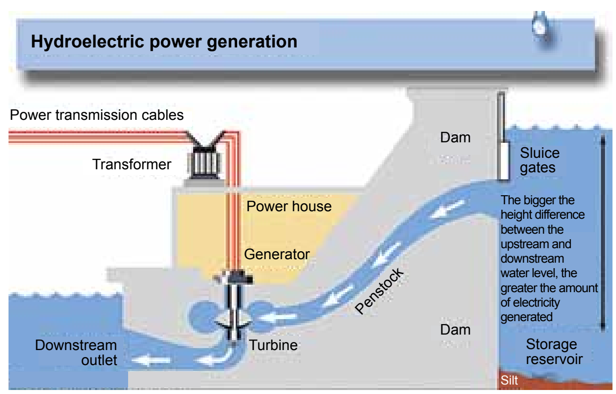
This chapter provides an overview of hydropower design schemes; it classifies hydropower plant types and describes main types of site layouts. The chapter describes structures and equipment that comprise a hydropower facility—civil works, electrical and mechanical equipment (E&M), steel structures and grid connection—and discusses structures to mitigate potential adverse environmental impacts. The function of each component of a hydropower plant (HPP) scheme is explained, along with how components function and respond to specific demands of local conditions.

4.1 General overview of hydropower schemes

Hydropower can be generated wherever a flow of water descends from a higher level to a lower level. The difference between the two water surface elevations is referred to as *head*. Head can exist in nature, for instance when a stream runs down a steep hillside or when a sharp change in elevation creates a waterfall in a river. However, head can also be created artificially by constructing a weir or dam; the dam creates a barrier to water flow, raising the upstream water level to the desired elevation.

As a result of elevation differences gravitational potential energy is stored in the water; this energy can be exploited by installing turbines and generators. Water flow moves the turbine blades, thereby converting water's potential energy into kinetic energy. The turbine rotation forces the generator rotator to spin around the stator thereby converting kinetic energy first to mechanical energy, and then to electrical energy. This concept is depicted below in a schematic illustration, Figure 4-1.

Figure 4-1: Sketch of a typical HPP with dam used for creation of head.



Source: Environment Canada

4.2 Classification and types of hydropower schemes

As mentioned earlier, each hydropower plant is site-specific, but plants can be classified according to the following parameters:

- Size or installed capacity
- Head availability
- Operation regime
- Purpose of plant structures

4.2.1 Classification by size

HPPs are commonly classified based on installed capacity P (MW). Opinions vary on the threshold that separates individual classes. HPPs are also classified based on dam head, as noted in the next section. The classification that follows is approximate but widely accepted; criteria vary among countries.

Micro P < 0.1 MW

1. *Small* 0.1 MW < P < 10 MW (some countries go up to 30-35 MW)
2. *Medium* 10 MW < P < 100 MW
3. *Large* P > 100 MW

1. *Micro* hydropower projects can supply electricity for an isolated industry, or small remote community. Usually, micro HPPs are stand-alone, i.e., they are not connected to the grid, and they are always run-of-river type. Small water storage tanks are sometimes constructed so that hydro generation is guaranteed for minimum period per day, even during low-water flow conditions. Micro hydropower schemes are commonly encountered in rural areas of developing countries where they provide an economical energy source without fuel dependency.
2. *Small* HPPs (Figure 4-2 and Figure 4-3) are dimensioned considerably smaller than medium and large HPPs because small HPPs usually exploit low discharges. Most small HPPs are run-of-river type (see also Section 4.2.3) that are connected to the power grid.

Figure 4-2: Installed Pelton turbine with two jets at SHPP scheme

Source: FICHTNER

Figure 4-3: Francis Turbine at the Three Gorges Dam in China

Source: Wikipedia

3. *Medium* hydropower schemes are either of the run-of-river or storage type and they almost always feed into a grid. Their layout may include a dam to create a head pond. The E&M equipment is similar to that of large hydropower schemes.[2]
4. *Large* hydropower schemes are always connected to a large grid; large HPPs can be run-of-river or storage type; each layout is site-specific and each plant's E&M equipment is designed for local needs and conditions.

4.2.2 Classification by head size

Depending on the head being exploited for electricity production, HPP schemes are divided into the following categories:

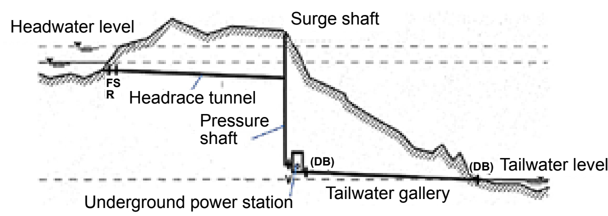
1. *High* head: H > 100 m
2. *Medium* head: 30 m < H < 100 m
3. *Low* head: H < 30 m

However, like classifications based on power output, definitions can vary by country and organization. The International Commission on Large Dams (ICOLD) defines a 'large dam' as one greater than 15 m in height. Also, classifying HPPs according to head may be inconsistent with classification based on power capacity. Power capacity is proportional to

Figure 4-4: Low head run-of-river HPP, Iffenzheim, Germany

Source: Wikipedia

Figure 4-5: Schematic illustration of a high-head HPP scheme with pressure tunnel, surge tank and pressure shaft as waterway, underground powerhouse and tailrace with open surface flow.



Source: Minor, Wasserbau

the product of available flow and head. Hence, even high-head installations might be characterized as micro or small HPPs.

Typically, mountainous terrain provides conditions necessary for implementing high-head (Figure 4-5) or medium-head HPP schemes, often storage-type. Lowland areas with wide river valleys provide locations feasible for installing low-head schemes, mostly run-of-river types (Figure 4-4).

4.2.3 Classification by operation

HPP schemes can be classified according to the type of operation as follows:

1. *Run-of-river* schemes
2. *Storage* schemes
3. *Pump storage* schemes

1. *Run-of-river* schemes generate electricity by immediate use of the inflow. As a result, run-of-river HPPs are subject to weather and seasonal variations resulting in variable power generation. Most run-of-river schemes have no storage capacity, or limited storage, which limits peak power operation to a few hours.
2. *Storage* schemes are characterized by water impoundment upstream of a dam structure to create a reservoir in which water is predominantly stored during high-flow periods and consumed for energy production during low-flow periods. Using stored water for the inflow to generate energy creates some security against natural fluctuations in water availability caused by weather and seasonal variations. Reservoir size determines the level of flow regulation.
3. *Pumped storage plants* are HPPs that can store water by pumping it from a lower reservoir or a river to a higher reservoir. Water is pumped during off-peak hours (lower power demand/ lower priced supply) by reversing turbine operation to make more water available to generate

2. Although projects under 100 MW would generally not be considered by developers to be "large," some European Union guidance related to the Clean Development Mechanism required additional assessment for projects over 20 MW.

electricity during peak demand periods. This process creates efficiencies of up to 80 percent—pumping uses 20 percent or more energy than the energy that is generated when an equal amount of water is released to generate electricity through the HPP.

For more information about pumped storage plants, please refer to American Society of Civil Engineers' "Hydroelectric Pumped Storage Technology: International Experience" (full reference provided in Section 16).

In terms of electricity production, storage schemes can provide peak energy at a planned/required time, while run-of-river HPPs can be used for generation only when water is available. Figure 4-6 shows an example of a daily demand profile. While the baseload plant satisfies the minimum load and operates 24 hours per day, additional power plants are needed to generate power when the demand increases.

A reservoir of stored water (volume in m^3) determines the potential for peak power supply—daily, weekly and monthly periods are common. Reservoir volume is directly related to the required period of peak power generation. Box 4-1 provides examples of storage and run-of-river HPPs.

4.2.4 Classification by purpose (single or multi-purpose schemes)

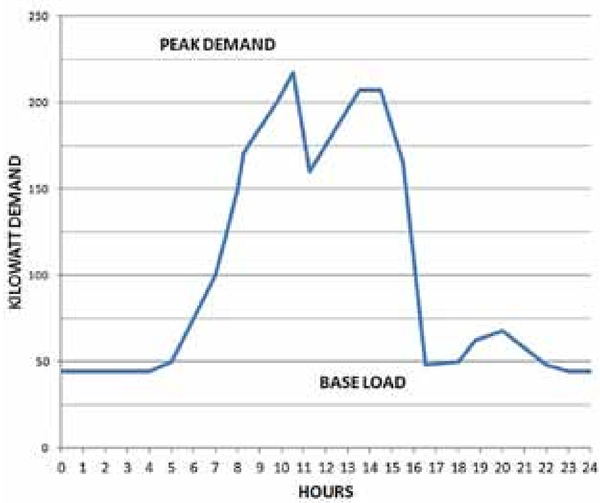
Multi-purpose schemes provide water for other uses for human subsistence and development. About one-third of existing hydropower projects serve other functions in addition to energy generation (LeCornu 1998).

The additional functions of HPP schemes may include the following:

- *Flood protection:* water storage reduces the impact of floods.
- *Drought mitigation:* supplement irrigation and community water supplies during dry periods.
- *Irrigation:* water for agriculture.
- *Water supply:* reservoir provides community water supply.
- *Improved conditions:* raising the water level in a reservoir improves conditions for navigation, fishing, tourism and recreation.

For more information about multi-purpose schemes, please refer to LeCornu's "Dams and water management" (full reference provided in Section 16).

Figure 4-6: Typical daily power demand profile



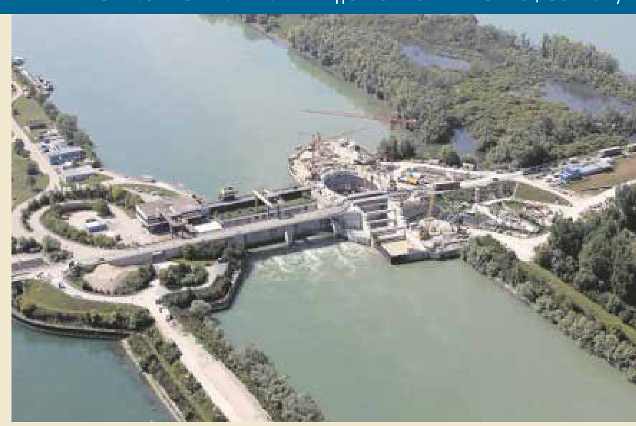
Source: FICHTNER

Box 4-1: Examples of storage and run-of-river HPP schemes

EXAMPLE OF STORAGE SCHEME: Hoover dam on Colorado river, USA	**EXAMPLE OF RUN-OF-RIVER HPP:** Iffezheim on Rhine river, Germany

Source: Wikimedia

- Installed capacity: 2080 MW
- Mean annual energy generation: 4.2 billion kWh
- Max head: 180 m
- Min head: 128 m
- 17 main Francis turbine generators and two Pelton Waterwheel station service units
- Reservoir total storage capacity: 36.8 billion m^3



Source: Wikimedia

- Installed capacity: 148 MW
- Mean annual energy generation: 730 Mio kWh
- Mean head: 11.0 m
- Maximum admissible turbine flow
- Q_{design} = 1,500 m^3/s
- Turbine: 5 Bulb turbines (Kaplan with horizontal axis)
- http://www.enbw.com

4.3 Site layouts

Local topography, hydrology and geology characteristics vary widely, which is why hydropower scheme layouts must be developed for each site in accordance with given natural conditions. In addition, each location has unique environmental and social conditions that affect hydropower facility layout and design. Therefore, each HPP layout aims to optimize the position of individual scheme components to fully exploit the natural resources of available head and stream flow in the most efficient manner—technically, economically and financially.

One task in the design of HPP scheme layouts involves positioning the powerhouse relative to headworks used for water diversion from the river course. In general, two options exist:

- Locate the powerhouse structure adjacent to the headworks
- Construct a diversion scheme so the powerhouse is built in a remote location downstream of the headworks to exploit a higher head.

If the river channel below the dam has an appreciable fall, economic studies should be made to determine whether a remote powerhouse location downstream from the dam is justifiable.

Existing topographical and geological conditions determine the length and the type of structures used to divert power water from river to powerhouse. Box 4-2 provides an example.

4.4 Components of HPP schemes

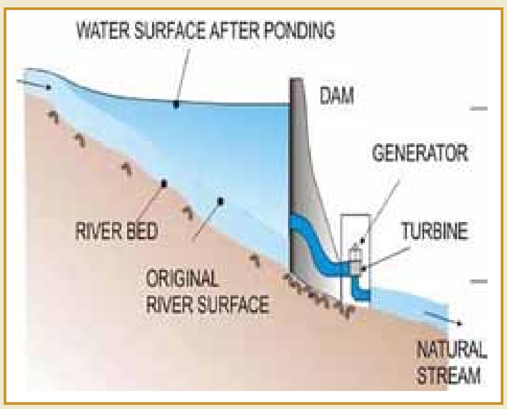
HPP scheme components can be grouped as follows:

- Civil works
  - Headworks
  - Waterway
  - Powerhouse and tailrace
- Electromechanical equipment
- Hydraulic steel structures
- Grid connection facilities

Box 4-2: Typical layouts of HPP schemes

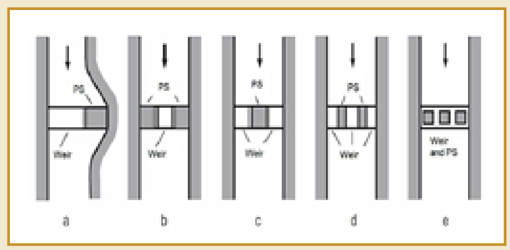
SCHEMES WITHOUT POWER WATER DIVERSION (POWERHOUSE INCORPORATED INTO THE HEADWORKS)

High and medium head schemes



Source: Strobl & Zunic, Wasserbau

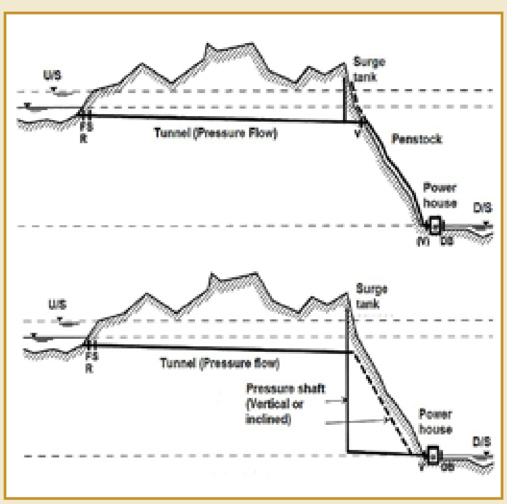
Low head schemes



Note: PS = Powerstation

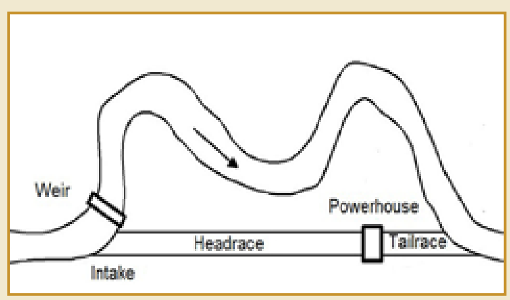
DIVERSION SCHEMES (POWERHOUSE IN REMOTE LOCATION DOWNSTREAM OF THE DAM)

High and medium head schemes



Source: Minor, Wasserbau

Low head schemes



4.4.1 Civil Structures

The civil structures that comprise a HPP scheme can be grouped as follows:

- *Headworks*: creates head, extracts water from the river course toward the generating equipment and allows safe passage of flood flows
- *Waterway*: conveys water to powerhouse
- *Powerhouse*: comprises structures to accommodate electromechanical equipment that converts water energy, first into mechanical and then into electrical energy
- *Tailrace*: discharges turbine water into a receiver, a river, lake or ocean
- *Auxiliary structures:* protect HPP scheme from potential risks such as turbine abrasion, sediment deposition in the waterways, and riverbed erosion downstream of the headworks

4.4.1.1 Headworks

Typically headworks comprise a structure to raise the water level to the desired elevation and a water intake structure to safely divert water from the river course to the waterway. In addition, headworks are designed to allow flood discharges to pass without risking structural instability, safe scheme operation, or upstream flooding.

Figure 4-7 shows a common diversion fixed-overflow weir to raise the water level on the right-hand side; on the left-hand side is a water intake with sluice gates to regulate the amount of discharge permitted into the waterway.

Figure 4-7: Diversion weir

Source: Prosem Engineering

To raise the water level, a barrier is constructed—a dam or a weir—that spans the cross-section of a river or a valley. Dams and weirs are defined as follows.

Dams

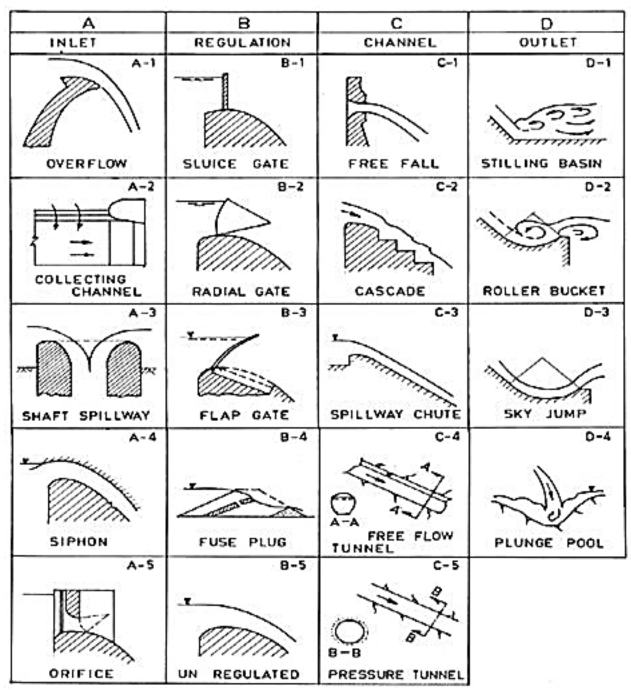
A dam is a barrier built across a stream or river to obstruct, direct, retard, or store the flow of water. As a basic element of a hydraulic scheme, a dam is used to create a reservoir and perform the following functions:

- Store water
- Increase the amount of discharge
- Ensure sufficient discharge during dry seasons
- Develop head by raising the water level
- Divert floodwater

Typically dams are classified (see also Box 4-3) according to their construction material. Today, the two most common construction materials are natural earth and concrete. In addition, dams are classified according to their sealing system or their static function. Natural clay, which has high flexibility and erosion resistance, is often used to construct the dam core and to seal the surface. This type of dam is especially suitable in seismic areas because of its high flexibility compared to rigid structures such as a concrete dam. A concrete dam can be considered if clay does not exist on site but sand and gravel are easily available.

Dams must be structured to safely convey normal stream and flood flows over, around or through. Dams must provide safe passage for surplus or excess water from the reservoir to the downstream river using structures known as spillways. Figure 4-8 shows common spillway types; an HPP spillway structure includes an inlet, regulation, channel and outlet structure.

Figure 4-8: Spillways classified by their inlet, regulation, channel and outlet structure



Source: Vischer & Hager (1988)

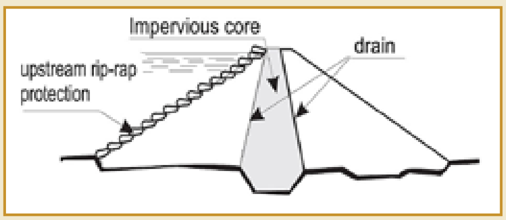
Box 4-3: Types of dams and selection criteria

TYPES OF DAMS

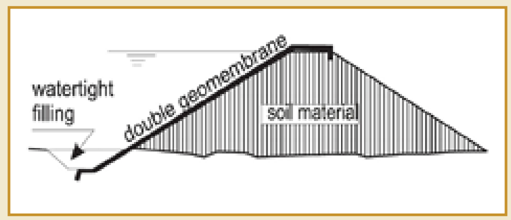
Dams are classified according to their:

- **Function served**
  - Storage dams: For permanent water storage
  - Detention dams: For flood retention
  - Diversion dams: The water level is raised to divert water
  - Debris dams: To hold off sediments
  - Coffer dams: To divert a river
- **Height** (Classification according to International Commission on Large Dams (ICOLD) which can vary from country to country
  - Major dams: Height > 150 m
  - Large dams: Height > 15 m, or 5 < H < 15 and storage capacity of reservoir > 3,000,000 m^3
  - Middle and small dams: Dams that do not belong in the above class
- **Construction materials**
  - Earth dams
  - Concrete dams
- **Sealing system**
  - Impervious core
  - Surface sealing

Dam with an impervious core



Dam with surface sealing

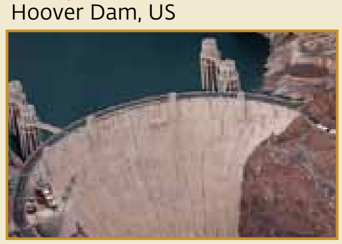


- **Statical function**
  - Embankment dams, i.e., dams made of natural earth material
  - Gravity dams
  - Arch dams
  - Buttress dams

Example of gravity dam:
Three Gorges Dam, China

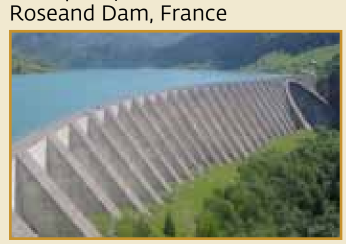
Source: Wikimedia

Example of arch dam:
Hoover Dam, US



Source: Wikimedia

Example of buttress dam:
Roseand Dam, France



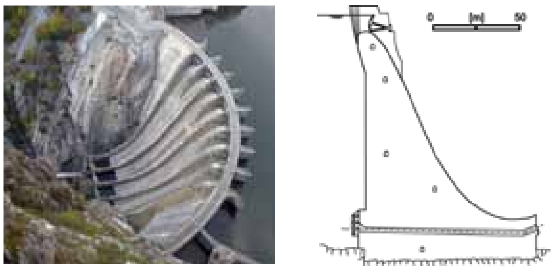
Source: Wikimedia

Criteria for selection of dam type

Factor	Condition	Dam type
Topography	Narrow U-shaped valley	Concrete overflow dams
	Narror V-shaped valley	Arch dams
	Low plain country	Earthfill dams
Geology	Solid rock	Almost every kind of dams
	Gravel foundation	Earthen and rockfill dams
	Silt and fine sand	Earth dams
	Clay foundation	Earthfill dams
Availability of Materials	The materials required for the construction of a specific dam type must be available locally or at short distances from the construction site.	
Seismicity	Earthquake zone	Preferably earthen and concrete gravity dams

Dams should have a drain or other water-withdrawal facility to control reservoir water level and to lower or drain stored water for normal maintenance works and emergencies. These are called bottom outlets (Figure 4-9).

Figure 4-9: Aerial photo and typical cross-section of Aldeadavila dam in Spain showing frontal type overflow spillway with roller bucket and bottom outlet



Source: Vischer & Hager (1998)

Weirs

A weir is an overflow structure built across an open channel to raise the upstream water level and/or to measure the flow of water. Its main purposes are similar to those of a dam and include the following:

- Divert water
- Increase water level to develop head
- Divert floodwaters safely

Unlike dams, weirs cannot be used for water storage; they only maintain the upstream water level at the intake.

Weirs are classified according to their ability to regulate the water level. Hence weirs with movable elements (Figure 4-11) can maintain a constant water level regardless of the discharge; with fixed overflow weirs (Figure 4-10) the upstream water level will change when the stream flow changes.

Figure 4-10: Schematic illustration of a fixed overflow weir

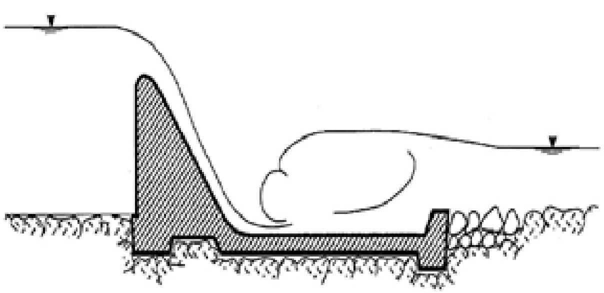
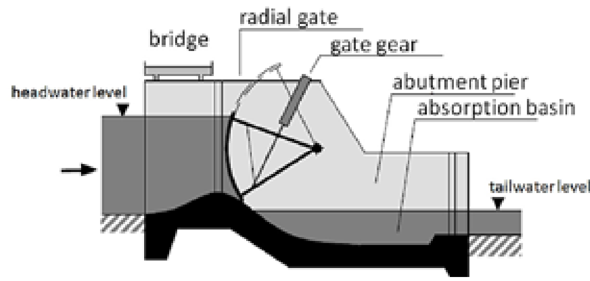


Figure 4-11: Schematic illustration of a weir with radial gates



Sizing

Dams and weirs must be stable under all possible loading conditions, including the following:

- Hydrostatic forces on the upstream and downstream faces
- Hydrostatic uplift acting under the base of the dam/weir
- Forces due to silt deposited in the reservoir
- Earthquake forces

The weir/dam spillway should be designed to have sufficient discharge capacity for a discharge flow with a specified statistical return period (e.g., 100 years or more). The discharge of spillway flow should not damage the dam. In addition, the dam structure should be designed to withstand higher discharges corresponding to the maximum flood water level (MFWL) without dam structure failure. The re-occurrence frequency of the design discharge is usually prescribed in national regulations or guidelines, and is usually defined by the impact on the downstream region that would be triggered by a dam breach or a weir collapse. A rough assessment in this case is that the design discharge capacity of the dam structure should approximate a flood event with re-occurrence period of 1000 years.

Intakes

The main function of an intake structure is to divert water into the waterway, which conveys water flow to the power plant in a controlled manner.

Intake structures are categorized as follows:

- Structures that take water directly from the water flow and divert it to the penstock
- Intakes which divert the flow through an auxiliary structure
- Structures located in reservoirs, e.g., towers

The main components of an intake include the following:

- *Screen* to prevent floating material from entering the waterway
- *Screen cleaning system*, usually a crane that removes debris from the screen
- *Intake gate* to physically disconnect the water flow in case of maintenance

Ideally, water intakes should be located along a straight section of the stream with a stable stream bed, constant flow, bedrock and small gradient. Typically, river bends or meanders should be avoided because the inner sides of bends accumulate sediment and the outer side is subject to erosion and flood damage. If positioning a water intake on a river bend is unavoidable, the outer side is preferable because the water intake will not be subjected to blockages from sediment depositions.

Intakes should be submerged deeply enough to prohibit vortex formation; typically the intake pipe should be submerged to a depth equal to three times the pipe diameter.

The intake can be located within the reservoir. In that case intakes can be constructed as towers (Figure 4-12) that provide water to the turbine-generator units through gated openings. The intake tower is connected to the dam with a bridge if the distance is small enough.

Figure 4-12: Intake tower in reservoir created by the Boulder dam, Colorado, USA

Source: Wikimedia

The Tyrolean weir is a common type of structure, especially in mountainous regions. It includes the intake and is built on the riverbed itself to divert the required flow while the rest of the water continues to flow over it (Figure 4-13).

Figure 4-13: Tyrolean weir

Source: FICHTNER (SHPP Velez, Serbia)

The Tyrolean Weir is self-cleaning due to the rake incline where any debris spills off during higher water flows; the incline also keeps larger pebbles and boulders out of the intake.

Weirs and intake structures are equipped with appropriate valves, stop-logs and gates, which form part of the plant hydro-mechanical equipment. This structure regulates water level and flow through the machinery. Hydro-mechanical equipment can be used to isolate sections of hydraulic structures to allow for maintenance or repairs.

Intake structures are usually the most maintenance-intensive components of hydropower schemes.

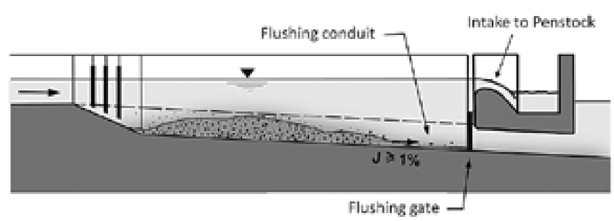
4.4.1.2 Waterway

The waterway comprises scheme components that convey water from the intake to the powerhouse. The conveyance layout can include either pressure galleries or pipes or a mixed system of free-surface canals and pressurized pipes. The waterway has additional structures to support a properly functioning HPP scheme; depending on local topographical and geological conditions these structures include some or all of the following:

Sand trap (grit chamber or desander)

Typically the sand trap is situated directly downstream of the intake and its function is to insure that sediment suspended in the water is removed before the water flow passes through the turbine. In medium-to-high head HPPs, suspended sediment wears down the hydraulic steel structures and turbines, reducing their efficiency and lifespan. The higher the available head, the smaller the size of particles that must be eliminated by the sand trap. As a rule, if the head is higher than 100 m, all particles larger than 0.2 mm must remain in the sand trap; for lower heads, 0.3 mm particles are acceptable. In addition to size, the design of the sand trap must consider particle content and shape (Figure 4-14). For example, hard minerals such as quartz and prismatic particles are more abrasive and therefore acceptable particle size should be smaller to reduce turbine maintenance costs.

Figure 4-14: Longitudinal section through a typical sand trap



Gravity combined with reduced flow velocity (caused by increasing the sand trap cross-section area) contributes to the settling of undesired particles. Usually the sand trap is connected directly after the power water is diverted from the river course or the reservoir. At the end of the sand trap is a slide gate that physically disconnects the water flow for maintenance. Next to the desander is a spillway that safely diverts the back-flowing water to an existing streambed or gully immediately after the slide gate is shut down.

Sand trap length is determined by intake discharge and by the required efficiency, i.e., the minimum particle size that will settle inside the sand trap and thus be prevented from entering the powerhouse. Therefore sand trap dimensions are calculated based on the size of particles trapped in the sand trap and the amount of time required for that size of particle to settle within the sand trap boundaries. This requires an estimate of the deposition velocity of a particle of a given diameter and the transfer velocity, which is assumed to be equal to the flow velocity. The determination of the deposition velocity is based on approaches that are reported in the technical literature.

Sand trap cost is largely determined by the volume of concrete required to build it; therefore the main parameters are particle size to be eliminated and the design discharge of the HPP scheme, which determine sand trap size and cost.

The sediment that settles in the sand trap is removed by opening a flushing gate so the water flow can transport the sediment back to the river.

A sand trap is usually omitted in large storage schemes because in reservoirs sediment may have time to settle, depending on water volume. In run-of-river projects most sediment remains in the water flow up to the turbines, making a sand trap essential in this type of scheme.

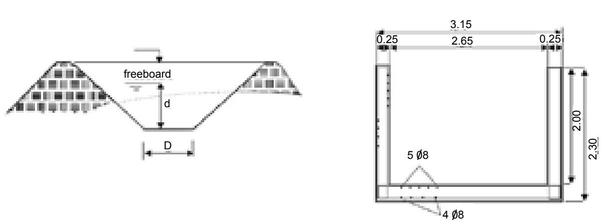
Headrace

The headrace conveys the water safely towards the forebay or the surge tank with minimum head losses. The headrace can consist of one or a combination of the following structures:

Open channel (canal) (Figure 4-15) with rectangular or trapezoidal cross-section. Rectangular channels are made of concrete; the trapezoidal shape can be designed as a stable earth channel.

Flow velocity should be higher than 1.0 m/s to avoid sediment deposition if no sand trap is installed upstream; omission of a sand trap may reduce conveyance capacity. However, channel flow velocity should be less than 1.5 m/s to avoid head losses and damage to the canal structure. To prevent water level fluctuations and consequent overtopping of the banks, a freeboard (vertical distance between the designed water surface and the top of the canal wall or bank) must be included in canal dimensions. Minimum freeboard for lined canals is about 10 cm, and for unlined canals, about one-third of designed water depth with a minimum of 15 cm.

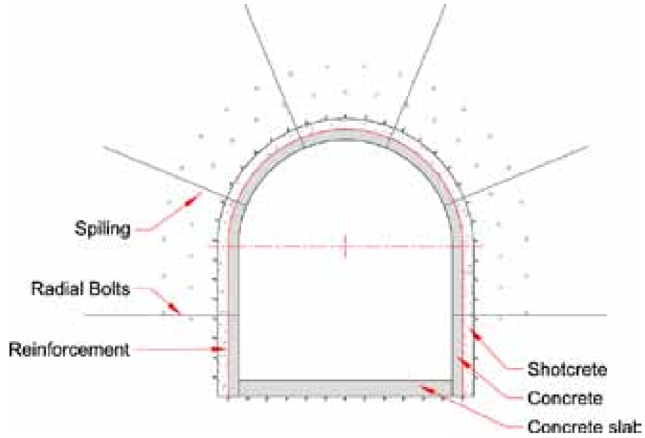
Figure 4-15: Embankment channel with trapezoidal cross-section and rectangular concrete open channel



Source: Layman's Guide to Small Hydro

Tunnels (Figure 4-16) are required when topographical conditions prevent open-channel construction. Tunnels require geological surveys to obtain crucial geology-related parameters such as rock quality, which influences cost; poor rock quality entails large costs. Water flow in a tunnel can be either free surface (similar to open-channel flow) or pressurized.

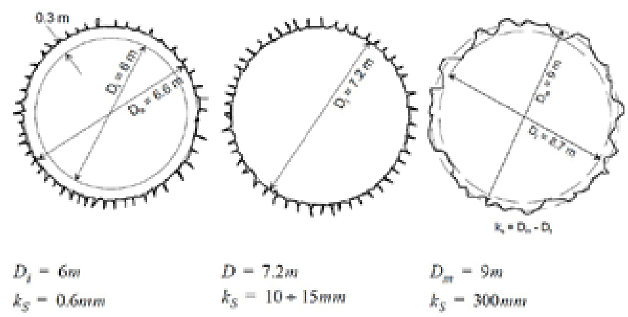
Figure 4-16: Typical tunnel cross section



Source: FICHTNER

Depending on prevailing rock conditions or the tunneling method, tunnels can be unlined, or lined with concrete or shotcrete (Figure 4-17). The lining selected and rock conditions will determine head losses and water losses due to leakage. Tunnel flow velocity is lower than 3-4 m/s to reduce head losses.

Figure 4-17: Comparison of lined and unlined tunnel cross-sections characterized by the same head losses.



Source: Minor, Wasserbau

Drill and blast is the conventional tunneling method in hard rock. Excavation is achieved by drilling a predetermined pattern of holes in the rock face, filling these holes with explosives, which are then discharged to crack and fracture the rock. Loosened debris is removed and the tunnel is secured.

The introduction of tunnel boring machines (TBMs) has increased tunneling efficiency and reduced costs. In successive operations TBMs can drill and then install tunnel support segments.

Forebay

This structure connects the headrace with the penstock and provides sufficient water volume for start-up processes, thus preventing air entrainment into the penstock, which could trigger water column collapse and associated pressure fluctuations. In addition, the forebay equalizes surge waves due to load rejection. Hence, required forebay volume and dimensions depend on HPP scheme design discharge.

Surge tank (surge chamber)

The surge tank controls pressure variations in the penstock and the headrace, thus eliminating or smoothing water hammer when variations occur due to sudden shutdown of the flow to the powerhouse. The surge tank also regulates water flow to the turbine by providing necessary retarding head.

The most common types of surge tanks are the following:

- Simple surge tank
- Restricted orifice-type surge tank
- Differential surge tank

Pressure pipe (penstock)

The penstock conveys pressurized water from the forebay or surge tank to the turbine. In addition to the pressure caused by static head, the penstock must be able to withstand the pressure rise caused by the so-called water hammer, i.e., the pressure rise that occurs due to rapid turbine shutdown in emergencies. Pipe thickness is based on the internal pressure the pipe material must withstand; higher internal pressure requires greater pipe thickness.

The penstock can be implemented on the ground or as a buried pipe. The penstock is always laid on a stable site, towards the hill slope and is held by anchor blocks, or supported by piers when necessary. Anchor blocks must be located everywhere the penstock changes incline or direction to ensure safe handling of the arising forces.

Two possible layouts for a penstock design include a separate penstock for each unit (Figure 4-18), or a penstock with a branch to the several units close to the powerhouse.

Figure 4-18: Steel penstock of the Walchenseekrafwerk (Germany)

Source: FICHTNER

Penstock materials can include the following:

- Steel and cast iron pipe, widely used in hydropower design, preferable for high-head plants.
- Plastic and glass-fiber-reinforced plastic (GRP) pipes lower friction losses but are more difficult to handle and install.
- Pre-stressed concrete pipes are cheaper but more difficult to install.
- Reinforced concrete pipe (available from sewage pipe producers) offers low cost, low maintenance, and a long service life, but is difficult to install and creates resistance problems.
- Pre-stressed reinforced concrete pipes can be used only in the low-pressure range (up to 15 bar, correlates with a pressure head of 150 m).

Penstock diameter and velocity are designed within an optimization analysis in which head losses are considered against penstock costs, which are determined by material, length, and thickness.

4.4.1.3 Powerhouse and tailrace

The powerhouse hosts the turbine, generator, and auxiliary equipment. The layout should allow easy installation of equipment and easy access for inspections and maintenance. Size depends on the types, dimensions, and number of units installed. In general, powerhouses have three primary areas.

- Main structure, housing the generating units
- Erection bay
- Service area that includes offices, and rooms for control and testing, storage, maintenance, auxiliary equipment, and special uses.

Powerhouses can be constructed above or below ground.

The crane is an important powerhouse component that is used to assemble generators, turbines and other components. Its maximum capacity must be equal to moving the heaviest equipment, such as generator parts or the turbine runner. The crane type should be considered during the design process based on powerhouse layout and dimensions. Three types of powerhouses are as follows, classified by how they house the main generating units:

- *Indoor type:* generator room is fully enclosed, with sufficient height to permit transfer of equipment by means of an indoor crane.
- *Semi-outdoor type:* generator room is fully enclosed but the main hoisting and transfer equipment is a gantry on the roof of the plant; equipment is handled through hatches.
- *Outdoor type:* no generator room; generators are housed in individual cubicles or enclosures either on the deck or recessed into the deck.

Positioning

Powerhouse location depends on the type of head utilization scheme. In medium-head and high-head schemes, the powerhouse is at the base of the dam, or at the end of a diversion structure downstream of the dam site; it can be underground to mitigate environmental impacts.

In low-head schemes the powerhouse structure is integrated with the weir; the power intake, turbine, generator, draft tube and tailrace are enclosed by the weir. In some cases the turbine and generator are integrated in a single waterproof structure that intersects the waterway. Powerhouse location should be based on the following factors:

- Spillway location, if the powerhouse is located adjacent to the dam
- Location of navigation locks (on navigation projects)
- Foundation conditions
- Valley width

- Accessibility
- Location of switchyard and transmission lines

In addition, the powerhouse location must be adequately protected against floods, by considering the following factors:

- Above anticipated flood-water level, which can be a flood occurring once in 100 years or once in 1000 years;
- Locate on the inner side of bends because the outer side is subject to erosion and flood damage;
- Do not locate too close to the stream;
- Use natural features and implement all necessary technical interventions, such as wing walls for flood protection.

The tailrace removes water from the powerhouse and turbine, therefore it must include a slope sufficient to prevent water backing up into the turbine; it must be oriented downstream to establish favorable flow conditions.

4.4.2 E & M equipment

4.4.2.1 Turbines

Classification

Hydro turbines can be grouped according to the head that they exploit to harvest hydropower, and their mode of operation.

A rough classification according to the available head (H) appears below:

- Turbines appropriate for low head H < 10 m
- Turbines appropriate for medium head 50 m < H < 10 m
- Turbines appropriate for high head H > 100 m

Another common classification of hydro turbines is based on their principle of operation—*impulse* or *reaction* type—that describes how the turbine transforms potential water energy into rotational mechanical energy.

The rotor of the reaction turbine is fully immersed in water and is enclosed in a pressure casing. The runner blades are profiled so that pressure differences across them impose lift forces, just as on aircraft wings, which cause the runner to rotate. Two main types of reaction turbine are the propeller (with Kaplan variant) and Francis turbines.

In contrast, an impulse turbine runner operates in air, driven by a jet (or jets) of water. Three main types of impulse turbine are in use: the Pelton, the Turgo, and the Crossflow.

Criteria for turbine selection

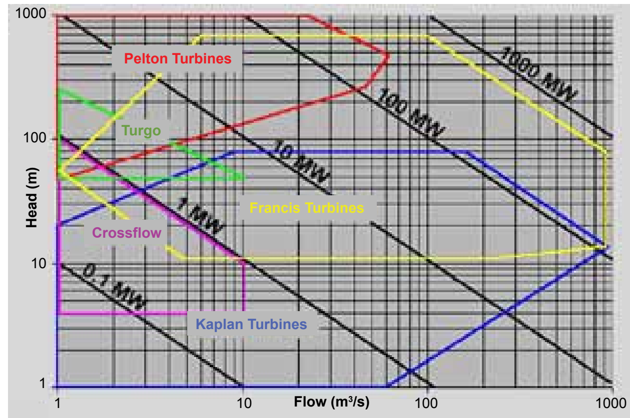
Turbine choice is based on the principal site characteristics—available head and flow—including flow variations, that is if the turbine operates in part-load condition, for example when available discharge throughout the year is typically lower than the turbine's design discharge.

The approximate ranges of heads, flows and power applicable to each turbine type are summarized below in Figure 4-19. These depend on the precise design of each manufacturer.

Impulse turbines

Typically, impulse turbines are more efficient for high heads. The Pelton turbine is the most widely used impulse turbine; it

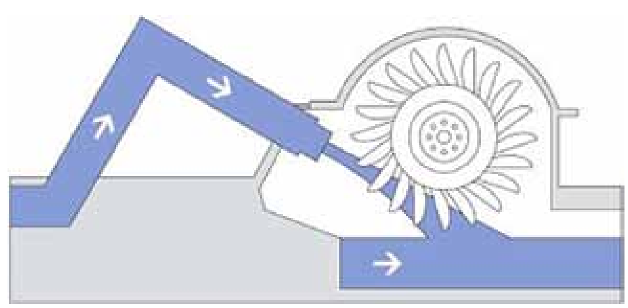
Figure 4-19: Head-flow ranges of hydro turbines



Source: Wikimedia

comprises a runner with blades shaped like a double spoon and one or more nozzles. The jet from the nozzle hits the runner blades and transforms the flow kinetic energy into rotational mechanical energy. Each nozzle has a movable needle to control its discharge. For a horizontal-shaft turbine, the maximum number of nozzles is two, for a vertical-shaft, the maximum is six. Each nozzle has a deflector, which is triggered when a load rejection occurs; it deflects the jet to control overpressure in the penstock and prevent runner overspeed. Pelton turbines operate in air (Figure 4-20).

Figure 4-20: Pelton turbine



Source: Verband der Elektrotechnik (VDE)

The main advantages of impulse turbines are:

- Easily adapted to fluctuating discharges with almost constant efficiency
- Avoid penstock overpressure and easily control runner overspeed
- Comparatively easy to maintain

The Turgo turbine is based on the Pelton turbine. The Turgo differs only in the angle at which the jet strikes the runner plane (about 20°). Therefore, water can enter at one side of the runner and exit on the other side so the flow rate is not limited by the discharged fluid interfering with the incoming jet (as in Pelton turbines). Consequently, the runner of a Turgo turbine can have a smaller diameter than a Pelton to produce equivalent power.

The Crossflow turbine or Banki-Michell turbine has a drum-like rotor with a solid disk at each end and gutter-shaped 'slats' joining the two disks. Water flows transversely through the turbine, entering at the edge and emerging on the opposite side thereby generating additional energy.

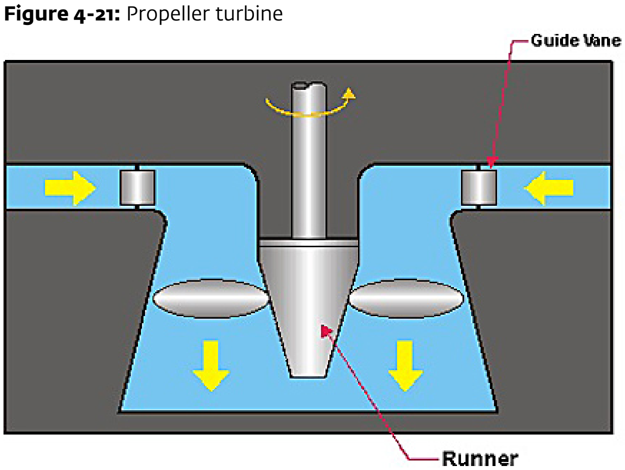
Reaction turbines

Reaction turbines use the water flow to generate hydrodynamic lift forces that propel the runner blades. Reaction turbines have a runner that always functions within a completely water-filled casing.

Reaction turbines have a diffuser known as a 'draft tube' below the runner through which the water discharges. The draft tube decelerates the water discharge and reduces static pressure below the runner, thereby increasing effective head.

The propeller turbine (Figure 4-21) is an axial-flow turbine with a propeller-like runner and three to six runner blades, depending on designed head. The runner operates like a reverse boat propeller. Various configurations of propeller turbines exist; for efficiency the water must have some swirl before entering the turbine runner. The runner absorbs the swirl and the water flow that emerges goes straight into the draft tube. Methods for adding inlet swirl include using a set of guide vanes mounted upstream to conduct the water spiral into the runner. Another method is to house the runner in a 'snail shell' so water enters tangentially and is forced to spiral into the runner.

Figure 4-21: Propeller turbine

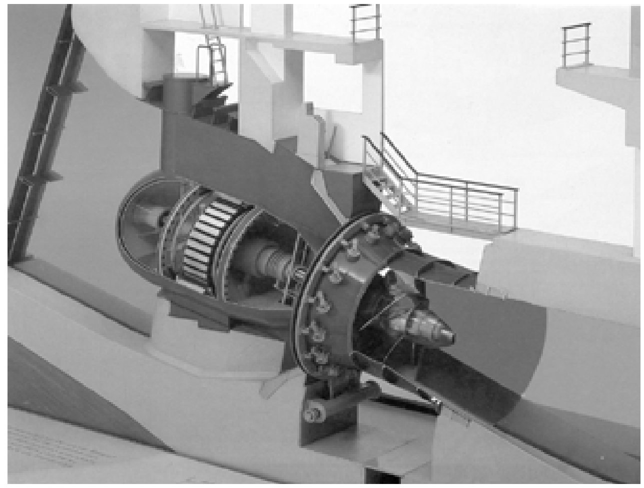


Source: Electrical and Mechanical Services Department, Hong Kong

Adjustable guide vanes can vary the flow admitted to the runner. The Kaplan turbine is a type of propeller turbine with adjustable runner blades as well. The mechanical equipment for adjusting turbine blades and guide vanes increases costs but improves efficiency over a wide range of flows. Double regulation of turbines is a feature now widely used for river installations with significant flow variations during an average year.

Bulb turbines (Figure 4-22) are named after the shape of the upstream watertight casting in which the generator is enclosed. Typically, bulb turbines are implemented in low-head hydropower schemes with high output. They are used in HPPs with head up to 30 m and offer reduced size and costs compared to vertical Kaplan turbines due to the almost horizontal water passage in the draft tube, which requires a smaller excavation.

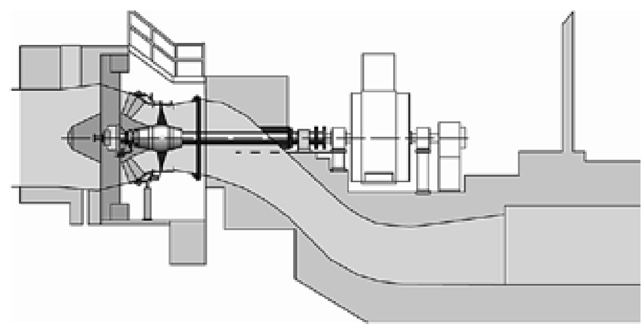
Figure 4-22: Model of bulb turbine (Lech-Staustufe 23, Merching, Germany)



Source: Strobl & Zunic (2006)

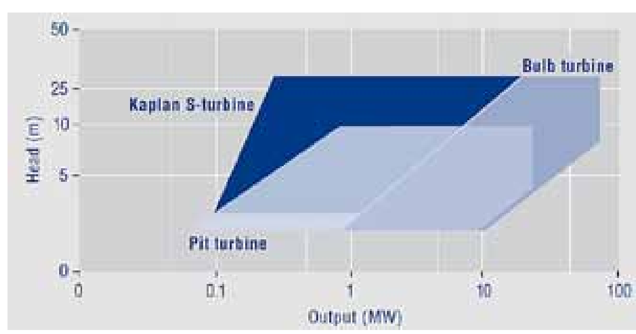
S turbines (Figure 4-23) provide an economic solution for low-head small hydropower schemes with capacity up to 10 MW (see Figure 4-24). The S turbine offers good accessibility to components, reliability and a long-service lifespan.

Figure 4-23: Longitudinal cross-section of s-turbine and generator.



Source: Strobl & Zunic (2006)

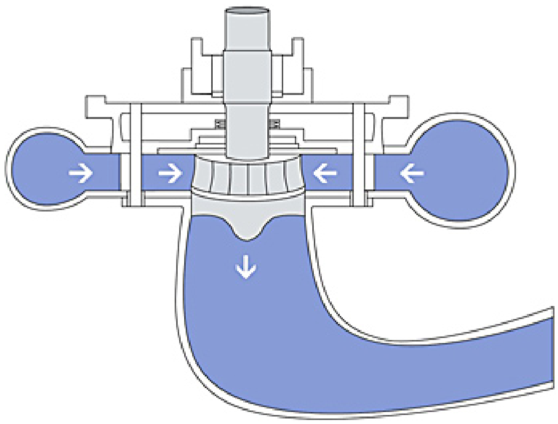
Figure 4-24: Application range of bulb design turbines



Source: Voith

The Francis turbine (Figure 4-25) is the most common water turbine in use today. Water flows radially into the runner and exits axially into the draft tube. The runner is surrounded by a spiral case in which guide vanes are integrated to direct the water tangentially to the runner.

Figure 4-25: Francis turbine with spiral casing



Source: Verband der Elektrotechnik (VDE)

The Francis turbine was originally designed as a low-head machine, installed in an open chamber without a spiral casing. Although efficient, the Francis turbine was eventually superseded by the propeller turbine, which is more compact and faster running for the same head and flow conditions. However, since many 'open-flume' Francis turbines are still operating, this technology remains relevant for refurbishment schemes.

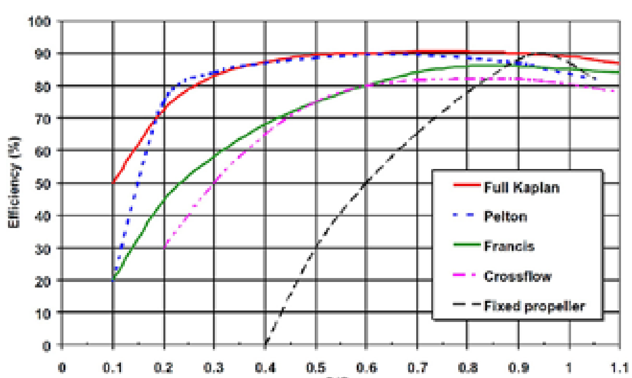
Advantages of reaction turbines are as follows:

- Requires less installation space (runners are smaller than Pelton runners)
- Provides a greater net head and better protection against downstream high flood levels because it can run submerged
- Offers greater runner speed
- Offers higher efficiencies for higher power values

Turbine efficiency

Turbine selection should include a comparison of the relative efficiency of turbine types and their operation under all conditions, especially reduced flow. Typical efficiency curves are shown in Figure 4-26.

Figure 4-26: Typical curves of part-flow efficiencies for types of turbines



Source: British Hydropower Association, Guide to UK mini-hydro development

The Pelton and Kaplan turbines retain very high efficiencies when running below design flow and operate well under part-load conditions. Cross-flow and Francis turbine efficiency drops more sharply if run at below half their normal flow, hence, they are used in run-of-river plant schemes with constant flow.

According to the part-flow efficiencies in Figure 4-26, it is practical to determine minimum admissible flow conditions, as a percentage of design flow:

- Pelton turbine: 10–20 percent of design flow (depending on number of nozzles)
- Francis turbine: 40 percent of design flow
- Kaplan turbine: 20–40 percent of design flow (double regulated/semi regulated)

If the flow falls below the minimum level, the power plant must shut down to avoid damaging the turbine due to heavy vibrations. Sometimes more than one turbine is installed to prevent turbine shutdown during low-flow season, depending on hydrological conditions and the hydropower scheme. General turbine improvement approaches are set out in Box 4-4.

Box 4-4: Technology improvement and innovation

The ongoing research aims to extend operational range, improve reliability, and reduce costs and environmental impacts. The main focus is utilizing low (< 15 m) or very low (< 5 m) heads. Thus, hydropower can be produced at many sites previously considered unsuitable due to the limitations of conventional technologies.

- **Variable-speed technology**
  Variable speed generation offers advantages, essentially based on greater flexibility of turbine operation in situations where the flow or the head deviate substantially from their nominal values. The main advantages relate to a considerable reduction of efficiency variability and reduced turbine abrasion from sediment-laden flows.
- **Matrix technology**
  This technology aims to develop small identical compact turbine-generator units, to be inserted in matrix-shaped frame. The number of units in the matrix can be adapted to available flow. During operation it will be possible to start and stop any number of units. Thus the units in operation will always run under optimal flow conditions. This technology is well-suited to installation at existing structures such as irrigation dams, ship locks, etc. where water is released at low heads [Schneeberger et al. 2004].
- **Fish-friendly turbines**
  A fish-friendly turbine is an emerging technology that provides a safe approach for fish passing though hydraulic turbines minimizing the risk of injury or death.
- **Abrasive-resistant turbines**
  Rivers often transport large amounts of sediment, especially during flood events. If the sediment contains hard minerals such as quartz, guide vanes, runners and other steel parts are subject to high abrasion, rapidly reducing efficiency. New solutions include coating steel surfaces with hard-wearing ceramic top layer.

4.4.2.2 Generator

The generator transforms mechanical energy into electrical energy using an excitation system.

Types of generators and classification

Depending on required runner speed and power station characteristics, the generator types are classified as follows:

- *Horizontal* and *vertical* hydro generators are classified by their axis locations. Usually, large and medium-sized units adopt a vertical layout; medium and small-capacity units adopt horizontal layouts.
- *Brushless excitation* generator and *excitation with brush* generator
- *Synchronous* generators are equipped with a DC electric or permanent magnet excitation system associated with a voltage regulator that controls output voltage before the generator is connected to the grid. Synchronous generator excitation is independent of the grid so synchronous generators can produce power even without grid connection. *Asynchronous* generators are unable to regulate voltage output and run at a speed related to system frequency; if isolated from the grid they cannot produce power because their excitation current comes from the grid.

Typical generator efficiency in SHPP installation schemes increases with rated power. For very small units (e.g., 10 kW) efficiency can be close to 90 percent; for larger capacities (> 1 MW) efficiency approaches 98 percent.

Criteria for generator selection

- Low-head run-of-river plants usually use low-speed generators in connection with Bulb or Kaplan turbines.
- High-head hydropower schemes usually require high-speed generators in connection with Francis and Pelton turbines.
- Variable-speed pumped-storage plants usually use asynchronous motor-generators that allow adjustments to the pump turbine rotation speed.

4.4.3 Hydraulic steel structures

Hydraulic steel structures are installed in HPP schemes to control water flow using gates or valves and are classified according to their operational purpose.

Service gates for continuous flow regulation in the waterway or of the water level in the reservoir include spillway gates, bottom outlet gates, and lock gates (for navigation).

Emergency gates are used to shut down water flow in conduits or open channels; typically they are designed only to be fully open or fully closed and they include intake gates, gates upstream of penstock service valves, draft tube gates, and gates installed upstream of bottom outlet gates

Maintenance gates are used to empty the conduit or canal for equipment maintenance (turbines, pumps or other gates); the most common type is the stoplog gate.

Distributor vanes or *turbine needle valves* are used for flow regulation.

Trash racks (or *screens*) are nearly always required at pressure pipes entrances and intakes to prevent floating debris from entering.

Today, the most commonly used gate types are *flap, cylinder, stoplog, slide, caterpillar, miter, roller, segment, sector, drum, fixed-wheel* and *visor*. Each gate type is unique in terms of purpose, movement, water passage, leaf composition, location and skin-plate shape. Gate type selection depends on purpose, dimensions of the opening to be gated, climatic conditions (e.g., passage of ice slabs) and options for gate operation.

4.4.4 Grid connection

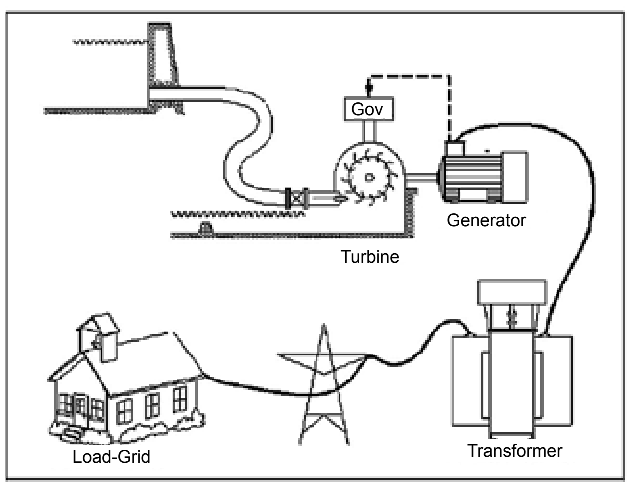
Before generated energy is transmitted through the grid, step-up transformers increase the voltage to reduce energy losses in the lines. Generated electricity is transmitted to a grid-connection point where electricity is converted to the voltage of the distribution network (Figure 4-27). In remote areas, new transmission lines can pose considerable planning hurdles and costs; it is easier and more economical to locate an HPP scheme closer to loads or existing transmission lines.

Location of switchyard

The switchyard transforms electricity voltage from low to high and performs several other functions; it is the gateway from the generating unit (HPP) to the distribution network. Switchyard location is determined by local topographic conditions and available space, but it should be adjacent or close to the powerhouse. Switchyard space requirements depend on the number and direction of outgoing transmission lines. Switchyard elevation should be above designed tailwater level; for instance above the level corresponding to a flood event with a reoccurrence period of 100 years.

At the beginning of a project, it is important to determine the value of electricity generated by the power plant, who will buy the power, and whether electricity generated can be used near the plant or must be transported to regions with higher power demand. In that case, electricity can be exported via the local transmission or distribution network through an agreement with the Transmission or Distribution Network Operator.

Figure 4-27: Grid connection



Source: British Hydropower Association, Guide to UK Mini-hydro Development

4.5 Summary: design and layout

Hydropower schemes are classified according to installed capacity, how dependent energy production is on available flow, head conditions, and potential for the scheme to be multi-purpose.

Each hydropower scheme layout is site-specific based on prevailing geological, topographical and hydrological conditions; therefore, scheme components may vary but will typically include headworks, waterways and powerhouse.

Headworks create head and divert water into *waterways* that convey water to the generating units. The *powerhouse* accommodates the turbine-generator unit and auxiliary equipment. A switchyard with a substation may be required to feed generated electricity into the grid.

The range of hydropower turbines provides a mature technology characterized by high efficiency. Each turbine type has an application range that is determined by available flow and head conditions at the site. The E&M equipment for each large hydropower scheme is custom-designed according to project requirements.

The following key factors affect design decisions, and in turn have an impact on HPP performance and costs:

- *Geological* conditions affect costs to stabilize the slope, foundation and tunneling.
- *Topographical* conditions determine scheme layout, specifically headworks height and length and available head for energy production.
- *Hydrological* conditions determine the flow available for energy production and the dimensions of intake structures, spillways and waterways.
- *Project location* determines accessibility and infrastructure costs
- *Distance from national network* determines the length of transmission lines required to transfer generated energy to the grid.
- *Environmental and social* considerations and associated mitigation measures determine costs and scheduling and may impact on flow available for production.

Hydropower development follows common economic principles for known sites, influenced by national energy strategies, domestic demand, export opportunities and anticipated power generation costs.

Project Development

5

An HPP project development, from concept to commercial operation, can be a long-term process of a decade or more, especially for medium and large HPP projects. Typically, the development process comprises seven major phases shown in Figure 5-1, but there are exceptions. Small HPP projects can employ shortcuts or skip steps and accelerate development.

Figure 5-1 shows development from a project developer perspective and from a financing institution perspective. The following section provides details of these phases.

5.1 Site identification/concept

Most potential sites for medium and large hydropower plants are already well known because in most countries potential sites have been located and assessed for master plans or similar studies during the second half of the 20th Century. It is likely that only a few as-yet unknown large and medium hydropower sites exist in developing countries such as Myanmar.

Hydropower development follows common economic principles for known sites, influenced by national energy strategies, domestic demand, export opportunities and anticipated power generation costs. Thus, in industrialized countries, the potential for economically attractive plants has been almost fully exploited. Most larger projects under preparation today are located in developing countries where the hydro potential is unexploited and demand for power is increasing. For small HPPs, potential exists throughout the world, but most of it is in developing countries.[3]

In Eastern/South-Eastern Europe, SHPP project developers can identify potential sites by checking readily available cadastral information. Past energy policy focused on medium and large projects, so smaller sites were overlooked.

In Africa and Asia, systematic information about potential sites for SHPP is scarce but geographic information systems and some hydrology measurements, can be used to efficiently locate potential SHPP sites.

After site identification, regardless of HPP scheme size—small, medium or large—site visits and basic data collection on site characteristics are required. This information will underpin the initial draft concept of a hydropower plant, which will be used to assess whether the identified scheme is worth pursuing. In parallel, the legal and regulatory framework must be analyzed to determine whether preconditions are met for successful HPP development. This includes water rights (concession), land acquisition, investment framework, and the power market model, which will reveal options for selling generated power.

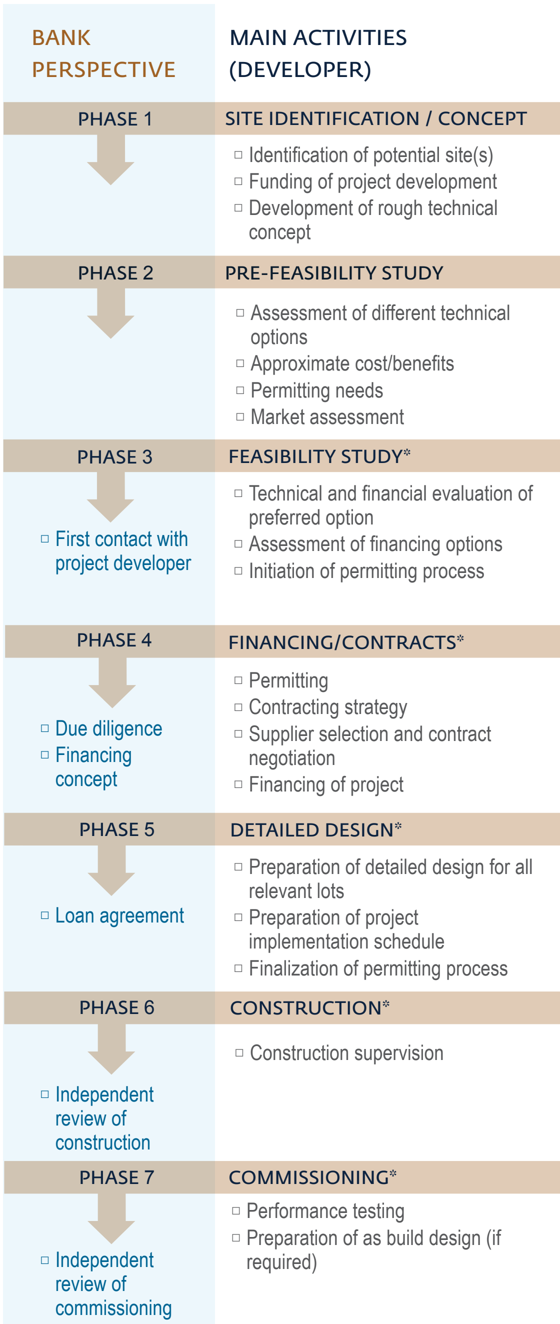
Project developers will continue project preparation *only* if technically suitable solutions are possible at a potential site, if a preliminary financial assessment reveals adequate returns, and if regulatory/permitting frameworks allow a plant to be constructed and operated for a reasonable duration. If pre-conditions are met, the next step is a pre-feasibility study (see Section 5.2).

The site identification/concept phase can be long, difficult and characterized by multiple attempts to identify suitable projects, but costs are minimal. In Table 5.1, rough time estimates are provided for HPP site identification. A seasoned project developer with experience in the country under consideration may be able to accelerate the process.

Costs associated with site identification and preliminary assessment are obviously linked to the time required to complete them, but in general the range is US$10,000–US$20,000 for a SHPP, if information is easily accessible. For a larger HPP, the range would be US$150,000–US$200,000, assuming intensive investigations are required. Typically, the developer funds these investigations but an alternative source of funding could be venture capital.

3. For further information about SHPP potential and installed capacity see also www.smallhydroworld.org

Figure 5-1: Typical HPP development steps



**Involvement of financing institution begins with Phase 3.*
Source: FICHTNER

Table 5-1: Estimated time required to identify an HPP

Type of HPP	Time required for first phase assessment
SHPP	1 – 6 months
Medium/large HPP	4 months – 1 year

Source: FICHTNER

5.2 Pre-feasibility study

The pre-feasibility study (PFS) undertakes further project assessment to answer the following questions. To answer the first question, the project developer needs to assess its financial attractiveness (expected return on investment) and identify potential deal-breakers.

1. Is the project financially viable?
2. If so, which technical option/concept is most attractive?

During the PFS the design concept is elaborated. Technical variants and options are explored and a preferred technical concept is selected—one that will maximize financial return. The PFS must also evaluate environmental and social aspects of the project. A preliminary assessment is undertaken to identify boundary conditions under which the project must be developed further, and to examine potential barriers.

The PFS phase requires acute attention to hydrological data, which is the decisive factor for plant design and resulting energy yield. Full clarity on this issue is required before the next phase can be triggered. The PFS may determine that additional hydrology data may be needed.

A PFS for small HPP is usually about 30 pages; for a medium/large HPP, up to 100 pages. The study includes a written report and drawings of major elements such as plan views and longitudinal or cross sections of headworks and powerhouse. About one month is required to prepare a PFS for a small HPP and three to six months for a medium/large HPP.

Box 5-1: Table of contents of a pre-feasibility study for a medium/large HPP

TYPICAL TABLE OF CONTENTS FOR A PFS FOR A MEDIUM/LARGE HPP

1. Introduction
2. Description of project
3. Topography
4. Hydrological analysis and sediment transport
5. Geology and geotechnics
6. Assessment of seismic hazards
7. Preliminary environmental and social impact assessment
8. Examination and evaluation of layout alternatives
9. Expected power production
10. Civil engineering design
11. Electro-mechanical equipment
12. Grid connection
13. Cost estimation
14. Permitting and licensing process
15. Planning and project implementation
16. Preliminary financial analysis
17. Preliminary risk analysis
18. Conclusion and recommendation

A typical PFS table of contents for a medium/large HPP appears in Box 5-1.

Up to this point in the project development process, financing plays only a minor role. However, the pre-feasibility study is often used to present the project to financiers. The next phase—the feasibility study—is used to develop a preliminary design and accurate investment requirements.

5.3 Feasibility study

The feasibility study (FS) is at the core of the project development process. Through extensive investigation, the FS assesses project viability, determines optimum project layout and all other requirements to further the project development process. When the FS is completed for a viable project, the information should be sufficient to support a decision about whether to proceed to project financing (appraisal and due diligence by financial institutions).

The FS structure is similar to that of a PFS, except FS detail is built up by collecting and analyzing additional data such as soil investigations/drillings, hydrological investigations, environmental/social research, and including a detailed elaboration of the design. An equivalent to the FS from the former Soviet Union is in Box 5-2.

The FS is built on PFS findings, which examined several potential technical concepts and selected the most viable. The selected concept is optimized during the feasibility study, which includes the following core elements:

- ***Technical concept:*** Specification and description of the most suitable layout and design for civil works, mechanical equipment, hydraulic steel structures, electrical equipment and grid connection, and optimization of the main power plant parameters such as head water level, installed flow, and so forth.
- ***Hydrology/energy production:*** Expected annual energy generation and impact of dry years on power output.
- ***Geology:*** Results of geological investigations, particularly for large civil constructions such as dams.
- ***Cost estimates:*** Detailed estimates of anticipated CAPEX (ideally based on budget offers), including range of contingencies and OPEX estimates.
- ***Power market:*** Identification of the off-taker of the generated electricity, preliminary price and duration of the power purchase agreement.
- ***Financial viability:*** Detailed financial (and if required, economic) analysis estimating the key financial parameters (IRR, NPV, LUC, etc.), which determine project attractiveness.[4]
- ***Financing options:*** Available equity, debt requirements, and other resources (e.g., subsidies and grants).
- ***Commercial arrangements:*** Identify the type of project [build-operate-own (BOO) or build-operate-transfer (BOT)] and start developing the procurement strategy including the number of contracts to be let and the O&M contract.
- ***Environmental and social:*** Results of environmental and social impact assessments and management plans, such as resettlement plans and contingency plans for issues identified.
- ***Permitting:*** Status of the process, overview of outstanding permits/licenses.
- ***Risk assessment:*** Summary of key project risks and mitigation options.
- ***Recommendations:*** For undertaking remaining project activities.

Box 5-2: TEO –Equivalent to feasibility studies in former Soviet Union countries

TEO – IN FORMER SOVIET UNION COUNTRIES (EQUIVALENT TO FEASIBILITY STUDIES)

The technical and economic justification (TEO) is a mandatory step if the project seeks governmental approval (e.g., if variable feed-in tariff applies or if the project applies for public funding). TEO includes technical design and cost estimates prepared by a licensed planning organization conforming to rules for development, coordination, approval and scope of technical and economic justification document (e.g., SP RoK 1.02-21-2007 in Kazakhstan).

Typically, TEO includes the following: market overview, technical concept, site description, architectural and civil works, engineering systems, environmental protection, social aspects, and financial and economic analysis. The cost estimate is prepared using standard software (e.g., Automated Calculation of the Costs Estimate, AVS), which performs calculations for civil works, installation and other costs using national government published fixed prices and factors for labor, material resources and services. Prices for tools and equipment are based on indicative offers and supplier pricelists.

Upon finalization, the state authority for project evaluation (Gosexpertiza) scrutinizes the documents, issues comments, then issues approval for technical concept and costs. The TEO approved cost estimate is a maximum cost that shall not be overrun at the later stages of project planning. For this reason, planning organizations try to integrate as many additional costs as possible to compensate for cuts during the approval process to provide more flexibility during the detailed engineering stage.

The FS includes drawings for general project layout, topography, dam site, waterways, powerhouse and other infrastructure; most FSs are 300+ pages.

The FS is the base document for project follow-up activities such as preparing tender design, and negotiating with potential financing institutions. The FS is also the basis on which lenders prepare their due diligence. Typically, the general design developed in the FS is considered final but the level of detail is elaborated later during tender and construction.

The FS is the basis for investors' final decision about whether to proceed. At this stage the project is already quite developed but negative FS results, such as inadequate financial performance or environmental and social constraints still have the potential to dampen investor willingness to proceed.

Small HPPs: Although many developers use a simplified approach for small HPPs including standardized equipment, this may be often shortsighted and more costly. In fact, some developers merge the PFS and FS into one document, or prepare the design based on PFS results, an approach that may appear

4. The methodologies for financial/economic analysis under PFS and FS are similar, however, the technical (and other) input parameters have more accuracy and detail in the FS.

to save time and money but is often the reverse. General studies without a detailed analysis of the plant concept can produce a sub-optimal plant design or other project pitfalls, such as overestimating hydrology, underestimating CAPEX, sub-optimal turbine design, among others.

The time required to prepare a feasibility study is in Table 5-2.

Table 5-2: Time requirement to prepare a feasibility study

Type of HPP	Time required for feasibility study
SHPP	2 – 6 months
Medium/large HPP	9 – 18 months

Source: FICHTNER

During the FS, the project developer and lenders establish first contact. For an initial general assessment, the PFS or an extract prepared from it is sufficient to approach a lender. During the FS, the potential lender might request additional documents and studies to decide whether a general interest exists in financing the project. If the lender is interested, and before it conducts due diligence, a mandate letter is usually signed with the HPP developer.

5.4 Financing and contractual arrangements

The development phase closes with financing and contractual arrangements. In addition, the developer finalizes permitting and licensing.

During contracting, plant construction contractors are selected based on the following selection principles, and depending on procurement strategy:

1. ***Prime contractor or turnkey EPC*** (engineering, procurement, construction) contractor: One contractor has overall responsibility for all lots including civil works, E&M equipment, grid connection, and so forth. Under the prime contractor option, one EPC contract is signed and the contractor is responsible for overall management of construction, especially interfaces among civil works, E&M equipment and grid connection. Risk is transferred to the prime contractor, which raises the overall contract price compared to a lot-by-lot contracting. Most financial institutions prefer turnkey EPC contracts.
   Typically the developer will engage an owner's engineer to supervise the prime contractor.

2. ***Separate contractors for each lot:*** For typical lots—civil works, E&M equipment, grid connection, penstock—separate EPC contractors are engaged. The developer assumes overall responsibility for plant construction and is likely to engage an owner's engineer, if its own engineering capacity is limited. The engineer will assume responsibility for contractor coordination, in particular for managing the interfaces among them. For larger HPPs this is a demanding and crucial activity that requires highly experienced engineering expertise.

For the procurement process, the so-called 'tender design' must be prepared. Tender design specifies detailed responsibilities for EPC contractors; and for lot-by-lot procurement, interfaces among the lots. To minimize construction risks, the developer must ensure the following:

- The EPC contractor has sufficient expertise and experience to supply and construct specified equipment.
- The proposed contract price, scope of delivery and schedule conforms to overall project documentation (cost estimates, time schedule, etc.).
- Potential risks, especially cost overruns and delays are balanced between contractor and project developer. Any non-fulfillment of contract obligations by the EPC contractor should be penalized.

During the financing and contractual phase of project development, before the start of the construction, the project must achieve financial closure. Most HPPs are financed through project or corporate finance (see Section 15).

At this stage, lenders are conducting intensive technical, environmental and social, financial and legal due diligence of the project using a team of independent advisors to review details of the feasibility study and draft contract agreements (e.g., power purchase agreement, EPC contracts, etc.). If the result is a positive assessment, agreement is reached on the financing package. Financial closure occurs when all required conditions have been met and all project and financing agreements have been signed. Financial closure might be achieved during this phase or in the detailed design phase.

The development phase could vary significantly, depending on the individual project. Small HPP can be developed faster, especially since financing is easier, but it can still take up to six months. In many cases, developers begin design and even construction before financial closure is achieved. To compensate for the risk if no loan agreement is signed, a higher equity contribution is required.

For medium and large HPPs, achieving financial closure takes much longer. Preparing adequate tender documents and procuring EPC contractors can take up to 18 months. For a build-operate-own (BOO) concept for project finance, the tender process can take up to two years.

5.5 Detailed design

After the EPC contracts are signed, contractor will begin preparing the detailed design, which is the basis for plant construction. Detailed designs are prepared for each plant component including intake/weir, desander, waterways, penstock, powerhouse, tailrace, substation, transmission line, and so forth.

The detailed design includes all specifications for quantities and materials. For lot-by-lot procurement, the owner's engineer must ensure that the interfaces among the lots are specified. The design must conform to national standards (see Box 5-3), but since national standards do not cover all aspects of hydropower plants, in particular medium and large HPPs, project designers can use standards and guidelines from the United States Army Corps of Engineers (USACE) or International Commission on Large Dams (ICOLD).

Box 5-3: Construction standards – Example for international project

CONSTRUCTION STANDARDS – EXAMPLE FOR INTERNATIONAL PROJECT

USACE Engineering Manuals

- **EM 1110-2-2104 (1992):** Strength Design for Reinforced-Concrete Hydraulic Structures, Change 1, 2003, US Army Corps of Engineers
- **EM 1110-2-2200 (1995):** Gravity Dam Design, US Army Corps of Engineers
- **EM 1110-2-2502 (1989):** Retaining and Flood Walls, US Army Corps of Engineers
- **EM 1110-2-1603 (1992):** Hydraulic Design of Spillway, US Army Corps of Engineers
- **EM 1110-2-3001 (1995):** Planning and Design of Hydroelectric Power Plant Structures, US Army Corps of Engineers
-

ICOLD Bulletins

- ICOLD Bulletin 148, Seismic Design and Performance Criteria for Large Storage Dams, 2012
- ICOLD Bulletin 75, Roller Compacted Concrete for Gravity Dams, 1989
- ICOLD Bulletin 82, Selection of Design Flood, 1992
- ICOLD Bulletin 129, Dam Foundations, Geologic Considerations. Investigations Methods. Treatment. Monitoring, 2005
- ICOLD Bulletin 61, Dam Design Criteria, 1988
- ICOLD Bulletin 58, Spillway for Dams, 1987

Developing a detailed design for a small HPP takes a few months and for a large HPP, more than a year.

5.6 Construction

Hydropower plant construction is a long process, in part because plants are often built in remote areas where access is difficult, and weather conditions can impede progress during cold or rainy seasons. Access roads and other infrastructure such as offices and worker accommodations must be built prior to beginning work on the HPP scheme. Construction time for smaller HPPs is 9–18 months, and for medium and larger HPPs, up to four years.

The construction process, in particular from the developer point of view, is described in Section 9. During construction, most lenders engage an engineering firm to monitor the process, and reviews are undertaken quarterly. Construction progress is monitored using contractor and engineering firm progress reports and site visits; an independent party reports to lenders.

5.7 Commissioning

The commissioning phase of HPP development requires civil, mechanical, and electrical engineering expertise to cover the broad spectrum of hydropower development. Lenders may also hire an independent engineer for the commissioning phase.

Before commissioning tests begin, all required documents—quality certificates, test procedures, tests results from equipment installation and all other tests—shall be made available to the lead commissioning engineer.

Details on commissioning testing phases are found in Section 10, and include the following:

1. *Dry tests:* after installation, equipment is tested in dry conditions to verify basic functionality
2. *Wet and load tests:* can occur a long time after dry tests if reservoirs must be impounded, coffer dams removed, and so forth
3. *Performance testing:* verifies turbine hydraulic efficiency and generator electrical efficiency
4. *Trial operation and reliability run:* requires 3-10 days for smaller HPPs; about 30 days for large HPPs

At the end of the commissioning phase, the project developer provides the contractor with a certificate and prepares detailed documentation of test procedures and results. The certificate declares acceptance of the HPP by the developer and usually it is linked to the release of the EPC from its obligations; also, the developer makes the final payment to the EPC.

The commissioning phase is shorter than earlier phases. Normally, each test takes about one month, and less time for small HPPs. The longest period might be between dry and wet testing; in large storage projects, the first reservoir fill might require more than two years.

Site selection involves identifying a location with a high water power capacity and finding the most suitable sites for the HPP structures at the identified location.

Site Selection

6

Every HPP is unique due to the constraints posed by hydrology, topography and geology. As a result, site selection is arguably the most crucial component of developing a viable HPP project and requires detailed investigation. More than other types of power plants, successful HPPs depend on site characteristics.

6.1 Introduction

Two main components of an HPP are the headworks, including an intake structure/dam, and a powerhouse. Since these structures are positioned some distance from each other and connected by waterways, site selection requires two suitable locations—for the intake and for the powerhouse.

In general site selection must consider potential energy generation (water power capacity), which depends on the head and the usable discharge, and potential constraints related to construction costs, plant operation and the environmental and social risks and impacts of the location. The following constraints must be considered: water resources, topography, geotechnical characteristics, site access, energy demand, interaction with other HPPs, construction constraints, grid connection, environmental issues, social issues, and financial incentives.

Therefore site selection involves (a) identifying a location with a high water power capacity and (b) finding the most suitable sites for the HPP structures at the identified location.

6.2 Basic data requirements

Data requirements increase with each phase of HPP development in level of detail, starting with site selection in the master plan and moving through pre-feasibility, feasibility, and so forth.

6.2.1 Hydrology

Available flow is the major input parameter, besides hydraulic head, that is responsible for the amount of energy that can be produced by an HPP. It is determined through a hydrological study that considers flow measurements, catchment area, precipitation, and flow distribution during the year.

A satisfactory statistical analysis of the hydrology of potential sites requires a period of at least 15 years of flow monitoring or precipitation monitoring. A flow duration curve (FDC) represents available flow and its distribution; the FDC is also used to calculate energy generation.

Detailed hydrological issues are discussed in Section 7.1.

6.2.2 Topography

Project topography outlines the boundary conditions and is therefore essential to select the HPP site and design. Data accuracy should increase with each project development step (e.g., site selection, pre-feasibility, feasibility, etc.). Usually, site topographic data is presented in a topographic map with a specified scale (e.g., 1:500), and a digital elevation model.

6.2.3 Geology

Detailed geological data are essential to design civil structures. To assist with site selection, initial assessments of the predominant rock type could be made using national geological maps. However, these are merely indicative and should be supplemented with deeper investigations, for example, geological mapping to create a detailed geological map of the project area.

Before the project feasibility phase, geological surveys must be conducted and followed up with laboratory analysis of samples. Two major activities for collecting samples are setting up test pits, and drilling boreholes.

Laboratory results determine rock and soil parameters, which is the basis for HPP design. It is worth repeating here that without accurate geological information on rock and soil parameters, an HPP design is based on unknown variables, which represents a significant source of risk.

6.3 Identification of locations with high water-power capacity

A river's theoretical water-power capacity is evaluated using the energy calculation equation in Section 7.2. To find the most promising sites along a river, usually using GIS (geographic information system) software, engineers calculate the potential energy generation of river segments of constant length. The water-power capacity of river segments is estimated using a calculation based on incline and available flow. Available flow is determined on the basis of expected precipitation rates, and the catchment area for each river segment. Thus, locations with the highest water-power capacity can be identified.

The most promising hydropower locations are determined by head and flow parameters. In most cases this means steeper topography (high head) in higher river segments and greater flow in lower river segments.

Therefore in higher locations, HPPs will provide a lower flow and higher head and in lower locations, HPPs will provide higher flow and lower head.

Maximum water-power potential is provided by a waterfall; the vertical water flow requires no horizontal distance for the drop.

6.4 Choice of locations for intake and powerhouse

Locations for the intake and powerhouse should be selected to optimize energy generation and cost.

Higher energy generation is achieved through high head and greater flow; both are considerations in selecting locations for the intake and the powerhouse. For example, if the potential intake location includes a waterfall of some meters height in its vicinity, the intake should be positioned upstream of the waterfall to exploit the additional head. If the potential location provides a tributary leading into the river, the intake structure should be positioned downstream of the tributary to exploit the additional water for energy generation.

The HPP costs are strongly influenced by installed capacity, distance between the intake structure and the powerhouse, and by multiple constraints acting upon the HPP (see Section 6.5).

If an HPP site offers options to position the intake and the powerhouse, an optimization analysis should be carried out that explores all possibilities, plus estimated revenues and costs, to identify the most financially attractive site.

6.5 Constraints

6.5.1 Water resources

As mentioned, available flow is of utmost importance for site selection. The amount of water and its annual distribution affects HPP project viability. The HPP energy output depends on annual flow distribution, hence, an HPP without a reservoir can produce energy *only* from available water and cannot compensate during dry periods. An HPP with a reservoir *can* compensate during dry periods by using water stored during wet periods and is able to produce energy during peak demand.

Average river-flow increases with every tributary discharging into it hence, flow increases going downriver. Therefore, if possible at the selected site, the HPP intake should be positioned downstream from a tributary discharging into the river, which would increase energy generation.

For high-head HPPs, it is common practice to increase the flow by collecting water from other springs and tributaries in the vicinity of the intake. In such cases the water of the springs/tributaries is captured and conducted to the reservoir/intake of the HPP, while strictly observing environmental standards, in particular minimum flow requirements in the tributaries.

When selecting a site and estimating energy generation, it is crucial to consider hydrological flow and other factors that may reduce flow available for generation, including minimum flow (a combination of environmental and social requirements, such as ecological requirements, irrigation usage and water supply), leakage, and evaporation.

6.5.2 Topography

Topography determines the relationship between useful head and waterway length ($\Delta H/L$). The head, $\Delta H/$, plus the flow, Q, determines energy generation potential, and the length of the waterway, L, affects construction costs. Therefore, higher $\Delta H/$, or steeper river topography produces a more cost-effective HPP.

One caveat is that a *very* steep terrain can restrict access and space. Building access roads through difficult terrain can be a project deal breaker due to prohibitive cost, and large structures such as a sand trap or powerhouse require considerable space; in steep terrain these structures must be constructed underground.

Further, topography and available head influence the type of HPP that can be built. In steep landscapes, a high-head HPP with Pelton type turbines will be more suitable; in flat regions, low-head HPPs with Kaplan turbines are favored.

Topography also dictates whether a storage reservoir can be installed. For example, a site in a steep valley is ideal to build a short/high dam to form a large reservoir at modest cost and effort; but a flat landscape requires long/expensive dam to form a reservoir. Hence, topography dictates the decision to build the HPP as storage or run-of-river.

6.5.3 Geological conditions

The geological situation at a potential HPP site is of crucial importance for power plant construction and operation. Costs can rise substantially depending on site geological conditions. First, the foundations of all HPP structures must be adapted to existing geological conditions, especially those of the dam and the powerhouse. Second, if tunnels are required, excavation costs can vary widely based on geological conditions. And finally, for HPPs with a reservoir, porous ground conditions, such as the permeability of karst, can lead to significant water losses.

6.5.4 Site access

All HPP structures under consideration require access using permanent or temporary roads. Site selection should consider whether access roads exist, whether they are in good condition or require upgrading, or whether new roads must be constructed.

6.5.5 Interaction with other HPPs

If HPPs are arranged in a cascade, selecting a new HPP site should ensure that the reservoir head water level does not impact the tailrace of the upstream HPP. Also, the reservoir head water level of the downstream HPP should not impact the tailrace of the new power plant. Furthermore, HPPs with a reservoir can have serious consequences for flow and annual flow distribution of reservoirs on downstream HPPs. Cumulative impacts on environmental and social aspects also need to be considered.

6.5.6 Grid connection

Transmission line construction costs rise as the distance increases between the HPP and the closest grid connection point so a site closer to an existing connection point is preferable.

6.5.7 Social and environmental issues

The environmental and social (E&S) impacts of hydropower plant development must be considered when selecting the site. Decisions should be guided by the mitigation hierarchy (anticipate and avoid, or where avoidance is not possible, minimize, and, where residual impacts remain, compensate or offset for risk and impacts on workers, affected communities, and the environment). An assessment of environmental and social risks and impacts must always be carried out, typically in the form of an E&S Impact Assessment (ESIA). The ESIA must comply with domestic environmental and social regulations and should follow Good International Industry Practice (GIIP) wherever possible. Where international lenders and/or Equator Banks or Export Credit Agencies are to be approached for lending, it is advisable to ensure that ESIAs follow international standards, such as the IFC Performance Standards and relevant World Bank Group Environmental, Health and Safety Guidelines.

Some typical issues to consider during the site selection process include the following:

- Loss of, or reduced functioning of, terrestrial (land) and aquatic (water-based) habitat
- Possible barriers to movement of fish, otters and other aquatic organisms, in particular aquatic migratory species
- Impacts on threatened and endangered species
- Need for minimum flow (ecological minimum flow and flow needed to mitigate impacts on cultural heritage and human downstream water users, such as irrigators, fish farmers, river rafters, fishermen)
- Community safety aspects such as dam safety, disease vector control and access control (to prevent drowning risks)
- Social impact assessments, involving matters such as possible resettlement of households affected by project infrastructure and/or flooding
- Public benefits (e.g., construction phase job generation, access road improvements)
- Construction phase noise, dust and vibration impacts, as well as worker health and safety, especially where tunneling is involved
- Stakeholder identification and engagement
- Cumulative impacts associated with other HPPs on the same river and/or in the vicinity

Refer to chapter 12 for some of the typical impacts and mitigation options for HPP projects.

The ESIA results are used to develop environmental and social management plans (ESMP) to define the mitigation measures for identified environmental and social risks and impacts. The ESMP, which may contain several plans—e.g., a Resettlement Action Plan, Biodiversity Management Plan, Spoil/Waste Management Plan or Stakeholder Engagement Plan—guides the developer during project implementation and operation.

The minimum flow depends on site-specific concerns or country-specific requirements. Its identification could be quite complex and usually needs specialized expertise. The entire process should be based on a good understanding of the site specific characteristic of the river, its flow regime, its ecology, the downstream uses and the impacts that the HPP operation may cause (e.g., base load vs peak load). Affected communities should be consulted where the river provides key ecosystem services that may be adversely impacted by changes in water flow (volume, timing, quality). Once the specific context is well understood, the key values to preserve need to be defined, which in turn leads to the selection of the most appropriate method to identify an adequate release. Monitoring plans should then be defined and implemented throughout the different stages of project development.

Results from the hydrological analysis, topographical data, and efficiencies of various HPP structures are used to quantify potential energy generation.

7 Hydrology and Energy Calculations

Value of expected energy generation is one of the most important determinants of HPP viability. The potential energy generation depends mainly on available flow and hydraulic head provided by topography. The amount and characteristics of water discharge at a potential HPP site are evaluated using hydrological analysis (see Section 7.1). Results from the hydrological analysis, topographical data, and efficiencies of various HPP structures are used to quantify potential energy generation (see Section 7.2).

7.1 Hydrology

7.1.1 The catchment area

The catchment area (also referred to as drainage basin or watershed) is the surface of the earth that is occupied by a drainage system, consisting of a surface stream or a body of impounded surface water together with all tributary surface streams and bodies of impounded surface water (Figure 7-1).

The catchment area is an important parameter to identify the available discharge at a specific location. Available flow, its characteristics, and head are important parameters to determine HPP potential energy output.

Typically, the water authority can provide measured discharge data for primary rivers and streams. Discharge data are unavailable for secondary rivers, since the discharge at a future intake location is not directly measured.

Figure 7-1: Catchment area of a river

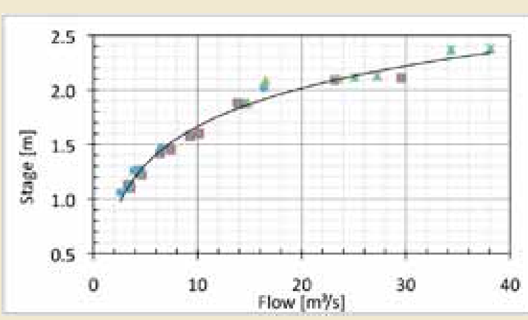
Source: Wikipedia

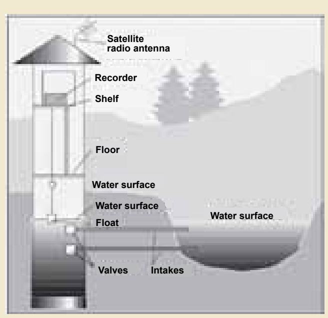
Box 7-1: Measuring and determining discharge

Gauging stations

Gauging stations are installed to measure discharge at a specific section of a river. The gauging station continuously measures the water level via the "stage - flow relation" (rating curve) to determine discharge. Gauging stations should be installed in sections of the river where the flow is as uniform as possible, as follows:

- Establish a rating curve
  Select the river section and then terrestrially measure a cross section through the river, up to the highest possible water level. Over a longer period (e.g., one year) continuously measure the flow for a wide range of water levels, related to the current water level. Using a current meter, measure the flow at many points along the cross section and use these measurements to establish the rating curve, indicating the stage - flow.
- Install the gauge
  Install a gauge to measure the stage (water level) at the respective river cross section and ensure that it can resist floods and vandalism. In the past, staff gauges were commonly used, which required manual metering of the water level. Today automatic gauges meter the stage on an hourly or daily basis and some can even transmit measurement data via GMS. Typical technologies for modern gauges include the following:
  - Pressure probes
  - Radar probes
  - Float operated probes





To determine the discharge at a future HPP intake, gauging station data must be transposed to HPP discharge characteristics. Usually data from the closest gauging station along the same river are used or, if these are not available, from an area nearby the HPP. Discharge data should be available for a period no less than 15 years, preferably consecutive, to derive statistically substantiated conclusions; the longer the period, the more accurate estimates will be.

The three most common methods to determine intake discharges are the following:

- Simultaneous flow measurements
- Relationship between specific runoff and altitude
- Catchment area method

Method 1: Simultaneous flow measurements: A temporary gauging point (so-called *control profile*) is implemented at a place of interest (intake location or its vicinity), usually upstream of an existing gauging station. The two points are measured simultaneously since the same weather conditions prevail. Thus, engineers can correlate measurements of the control profile (temporary station) with those of the gauging station. Next historical hydrological data are transposed from the existing gauging station to the proposed intake. To cover all flow conditions, measurements must be undertaken during dry and wet periods—at least five dry-period, five average-period, and five wet-period measurements to correlate gauging stations. The more simultaneous measurements there are, the more accurate the correlation will be.

This is the most accurate method to transpose historical flows from a gauging station to an intake location. Measurements and transposition calculations must be carefully documented.

Method 2: Specific runoff - altitude relationship: An alternative approach is to empirically derive a relationship between specific runoff [l/s/km²] and average catchment area altitude. Data from multiple gauging stations and control profiles in the area can be used to generate the regional function (curve).

The underlying idea is that the higher the catchment area, the more expected runoff per km². After average flow (MQ) is determined using this method, the value is compared to the MQ at the next gauging station and the correlation is determined, then historical hydrological data can be transposed to the intake.

The accuracy of hydrological data obtained by this method depends on (a) the accuracy of data used to prepare the function; and (b) the method used to determine the average height of the catchment area.

Method 3: Catchment area: This method assumes that in a specific gauging station catchment area the same quantity of runoff is generated on each km², independent of elevation. Thus intake discharge is calculated as a function of the catchment area as shown in the box below.

The method is a simple approximation, which works best when the gauging station is close to the respective intake. This method *does not* consider the influences of vegetation, soil type, and geology on the flow in the investigated area. Therefore, when HPP development reaches the design and construction phase, hydrology should be verified, for example by Method 1 (simultaneous measurements) and if possible, by installing a permanent gauge at the future water-intake location.

$$Q_{Intake} = Q_{Gauginstation} \cdot \left(\frac{Area_{Intake}}{Area_{Gauginstation}} \right)$$

Where

Q_{Intake} = the estimated discharge at the intake intake in m³/s

$Q_{Gauginstation}$ = the discharge at the next gauging station in m³/s

$Area_{Intake}$ = the catchment area at the intake of the respective HPP in km²

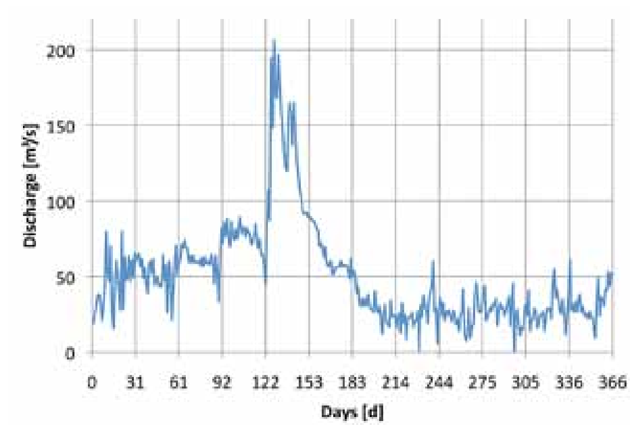
$Area_{Gauginstation}$ = the catchment area of the next gauging station in km²

7.1.2 Flow duration curve

Water discharge at a given river cross-section varies over time. Factors that control temporal variations of flow discharge include temporal variations of precipitation intensity and corresponding surface run-off. Water discharge may be measured multiple times during the day, depending on the measuring device employed. By averaging measurements taken throughout the same day, the *mean daily water discharge* can be calculated. Further, averaging annual historical mean daily flow values defines the *mean annual water flow* value for a given year. If flow measurement records cover a considerable time period, then mean annual flows calculated for each year will reveal a fluctuation around a mean value. This is the *mean annual flow* at the specified location, characteristic of the river reach that provides an idea of flow power potential.

However HPP planning requires more detailed knowledge of the river flow regime. Two ways of expressing the variation in river flow during the year are the annual hydrograph and the flow duration curve (FDC). The annual hydrograph is easier to understand since it shows daily flow variations during a calendar year (Figure 7-2).

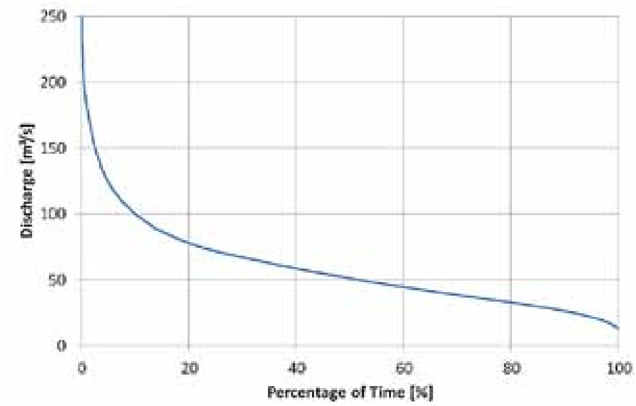
Figure 7-2: Annual Hydrograph



Source: FICHTNER

However, the FDC is more useful to calculate energy available for a hydropower scheme. The FDC shows temporal flow distribution, usually during a year. All values of a series of flow records from a river gauging station (preferably no fewer than 15 years) are ordered from highest to lowest values. The frequencies converted into percentages of the total number of days form the basis for the FDC (see Figure 7-3). This flow series can comprise daily, 10-day, or monthly average values. The smaller the averaging period of flow values, the more accurate the flow duration curve, and the energy calculation. In many cases, only monthly average values are available, which can cause deviations of up to 10 percent or more in the energy calculation, compared with an energy generation calculation using daily values, depending on the HPP site.

Figure 7-3: Flow duration curve based on daily flow values for a 40-year period



Source: FICHTNER

The vertical axis represents flow, the horizontal axis represents the percentage of the year that the flow *equals or exceeds* the value on the vertical axis. For example, the FDC can immediately indicate the flow level that will be available for at least 50 percent of the year (known as Q50). The flow exceeded for 95 percent of the year (Q95) is often assumed to be the characteristic value for *minimum* river flow.

Typically FDCs are similar for a region, but they can be affected by soil conditions, vegetation cover, catchment shape, and by reservoirs, abstractions and discharges that have been built in the area.

A flatter FDC is preferable because it indicates that total annual flow is spread more evenly during the year, resulting in a longer period of useful flow and less severe flooding. For reliable statements, collected flow data should cover at least 15 years.

Stream flow provides the energy produced in a hydropower plant. However, if the water discharge significantly surpasses the mean annual flow (i.e., during a flood event), the stream flow may endanger the operational and structural safety of the scheme. According to European Union Directive 2007/60/EC regarding the assessment and management of flood risks, a flood event is defined as "the temporary covering by water of land not normally covered." For this reason, the hydrological study must focus not only on water availability for energy production, but also on determining flow discharge during flood events of a specified frequency and severity. Knowledge of extreme flow values observed in the river reach allows planning for flood protection measures to assure the safety of the HPP scheme.

Two values of flood events are of interest in HPP design. First, is *normal operation* design flood, defined as maximum water discharge conditions under which the facilities can maintain normal operations. Usually, these floods are described in terms of a specific return period such as, one occurrence in every 100 years. Requirements for the return period of the design flood are usually specified in national legislation or industry guidelines, which distinguish between high, medium and low hazard structures.

Second, is the *maximum inflow* design flood, which is the maximum flood discharge that facilities should withstand without risk of dam failure or serious damage to hydraulic structures, referred to as probable maximum flood (PMF or 10,000 years return period). Usually, maximum flood is estimated by running a hydrological computer model of the hydraulic basin based on existing rainfall and snowfall records.

7.2 Power and energy

Generally and per definition, energy is the amount of work done over time, or a capacity to do work. It can be measured in joules. Electricity is a type of energy, but is generally expressed in megawatt-hours (MWh):

$$E = P * t$$

Where:

- **E** is the generated energy [MWh]
- **P** is the power produced [MW],
- **t** is the period of time [h]

1 MWh is equal to 3,600,000,000 joules. Power is the energy that is converted per second, i.e., the amount of work being done within that second, measured in watts (where 1 watt = 1 joule/sec. and 1 kilowatt = 1000 watts). Other metric prefixes are given in Table 7-1.

Table 7-1: Clarification of metric prefixes

Unit	Watt
1 Watt [W]	1
1 Kilowatt [kW]	1,000
1 Megawatt [MW]	1,000,000
1 Gigawatt [GW]	1,000,000,000

Source: FICHTNER

Hydro-turbines convert water pressure into mechanical shaft power, which is used to drive a connected electricity generator. Available power is proportional to the product of head and flow rate. The general formula for any HPP power output is:

$$P = \frac{\eta * \rho * g * Q * H}{10^6}$$

Where:

- **P** is the power produced at the transformer [MW]
- η is the overall efficiency of power plant [-]
- ρ is the density of water [1000 kg/m³]
- **g** is the acceleration due to gravity [9.81 m/s²]
- **Q** is the volume flow rate passing through the turbine [m³/s]
- **H** is the net head [m]

For rough estimation, 87 percent is used as typical overall plant efficiency, then the above equation simplifies to:

$$P(kW) = 8.5 * Q * H$$

Installed capacity is among the most important figures to characterize a hydropower plant; it is defined as the designed power output of the installed turbine units. Installed capacity depends primarily on available head (see Section 7.2.4), and on design discharge (see Section 7.2.3); it is calculated according to the equation shown above using design discharge, $Q_{D,}$ and net head and the overall efficiency at design discharge.

Detailed parameters essential for power and energy calculations are discussed in the following sections.

7.2.1 Efficiency and losses

Overall HPP efficiency includes the efficiency of the turbine, generator, and transformer. If the metering point is far from the HPP, electricity transmission efficiency must also be considered. Overall efficiency is determined as follows:

$$\eta_{overall} = \eta_{Turbine} * \eta_{Generator} * \eta_{Transformer}$$

The most efficient turbines can have hydraulic efficiencies in the range of 80 to over 90 percent (higher than all other prime movers), see Table 7-2.

Table 7-2: Efficiencies of electrical equipment

Item	Efficiency
Generator	90–98%
Transformer	98–99.5%

Source: FICHTNER

As mentioned in Section 7.2.4, *gross head* reduced by energy losses is called *net head*. Energy can be dissipated by friction and turbulence. Two main categories of head loss are defined in terms of local losses and friction losses. Most local losses are a small fraction of gross head and occur at the trash rack, inlet/outlet, bends, and valves.

Friction losses occur due to friction along water conveyance structures such as pipes or canals; the degree of loss varies according to pipe or canal length and roughness (Table 7-3), and flow velocity. Lower head losses occur under conditions of smoother shorter conveyance structures, and lower velocity flows.

Table 7-3: Surface roughness of pipe materials

Material	k [mm]
PVC	0.003
Steel	0.01–0.05
Concrete	0.2–10

Source: FICHTNER

7.2.2 Turbine efficiency

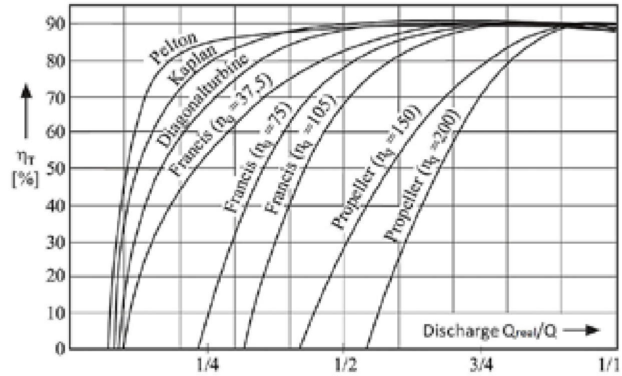
Turbine efficiency ratings are important to compare different turbine types and their performance under conditions of reduced flow. Typical efficiency curves are shown in Figure 7-4.

Pelton and Kaplan turbines retain high efficiencies when running below design flow, exhibiting good part-load behavior. The efficiency of the Cross-flow and Francis turbines drops more sharply if run at below half their normal flow, hence they are more suitable for run-of-river plant schemes with constant flow.

According to the part-flow efficiencies shown in Figure 7-4, it is practical to determine minimum flow conditions that relate to design flow and vary widely, depending on turbine design:

- Pelton turbine: 10–20 percent of design flow (depending on number of nozzles)
- Francis turbine: 40 percent of design flow
- Kaplan turbine: 20–40 percent of design flow (double regulated/semi regulated)

Figure 7-4: Efficiency of turbines types , Q_{real}/Q_D is the relative discharge related to the design discharge and η_T is the efficiency



Source: J. Giesecke, E. Mosonyi, Wasserkraftanlagen, 2009

If the river falls below minimum flow, the power plant must shut down to avoid turbine damage due to heavy vibrations. If low flow is to be used for power generation, more than one turbine is installed to prevent turbine shutdown during low-flow season, depending on the hydropower scheme.[5]

7.2.3 Discharge/design discharge

The discharge available for energy production depends on hydrology, the ecological flow to remain in the riverbed, irrigation requirements, leakage, evaporation, and other water consumption.

A flow duration curve (FDC) is a statistical representation of the amount of hydrologically available water, and the distribution or characteristics of annual flows. A rather flat FDC implies a constant flow with low fluctuations and small differences between low and high flows. A steep FDC indicates large flow differences between dry and flood seasons, and high variability.

Typically, the choice of design discharge—a run-of-river scheme or a storage power plant—is based on hydrological characteristics, in addition to energy demand, topographical conditions, environmental and social considerations, and other factors.

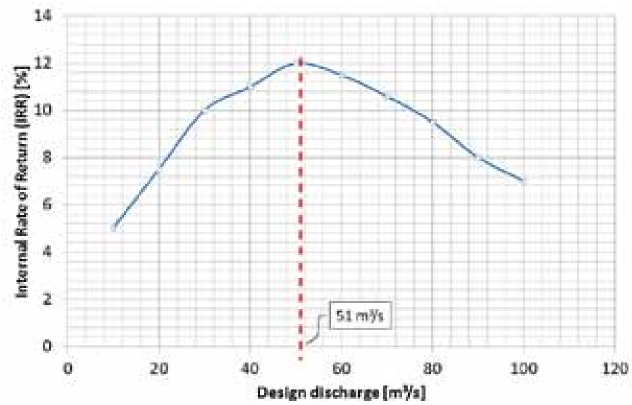
Besides general considerations, design discharge selection for specific conditions of topography, hydrology and geology should be based on an optimization procedure to maximize natural resource exploitation while satisfying private and public interests.

The design discharge is optimized by comparing project benefit/cost for each design discharge alternative. This is done by discounting CAPEX (capital expenditure), OPEX (operational expenditure) and revenues from electricity generation, and calculating financial indicators for each alternative. As financial indicators, usually the internal rate of return (IRR), the net present value (NPV), benefit/cost (B/C) ratio and the levelized cost of electricity generation (LCOE) are used.

Figure 7-5 shows an example of the estimated IRR in relation to the design discharge; the optimum design discharge is reached at 51 m^3/s. Stepwise changes of the IRR are caused by stepwise changes of costs of different turbine units and changes to penstock diameter.

5. For example, instead of installing one 60 MW Francis unit, two units of 30 MW each could be installed, which would allow minimum flow of 20 percent of the design discharge instead of 40 percent. Generally each scheme requires an assessment to evaluate whether installing more units is technically possible and whether additional power generated by two units will create sufficient benefit to compensate for additional costs.

Figure 7-5: Financial optimization of the design discharge



Source: FICHTNER

In general for the design of new HPPs, optimization procedures are done not only to determine the design discharge, but also to optimize the penstock diameter, the full-supply level in reservoirs, and the number and design of turbines.

For run-of-river power plants [Giesecke and Mosonyi 2009], the recommendation is to choose a design discharge that is available 100 to 120 days a year or about 30 percent of the time. This value is a rough first estimate that is further optimized as the project moves through development phases and analyses become more detailed. Optimum conditions for run-of-river HPPs are given when the FDC is flat. The level of use for run-of-river is characterized by the following ratio and usually ranges from 1.0–1.5 but varies widely depending on the shape of the FDC.

$$f_a = \frac{Q_d}{Q_{av.}}$$

Where:

- f_a is Level of use [-],
- Q_d is the design discharge [m³/s],
- $Q_{av.}$ is the average discharge [m³/s]

The high fluctuations represented by steep FDC require either a lower ratio $Q_d/Q_{av.}$, which also results in less energy generation (see Figure 7-6), or a storage reservoir to compensate for differences between high and low flows. Depending on inflow regulation capacities, storage power stations are categorized as daily, weekly, monthly or annual stores. Larger reservoir storage correlates with longer inflow regulation intervals, implying better power generation regulation capacity. The level of use for reservoirs characterizes reservoir regulation capacity and is calculated as follows:

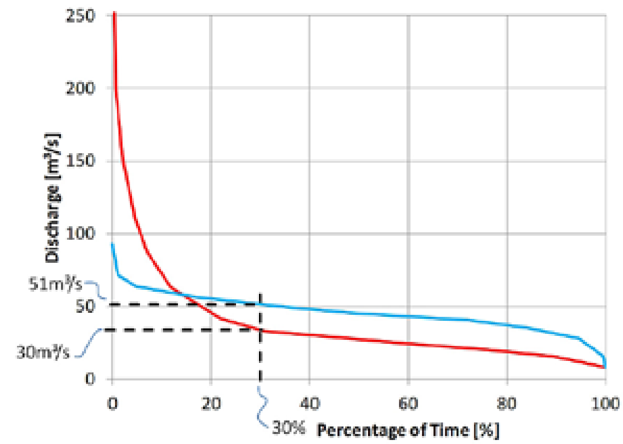
$$f_a = \frac{V_{reservoir}}{V_{in}}$$

Where:

- f_a is Level of use [-],
- $V_{reservoir}$ is usable storage volume of the reservoir [m³/s],
- V_{in} is the volume of water flowing into the reservoir during one year [m³/s]

Storage power plants can be operated to produce peak energy, in which case a higher design discharge/capacity is installed and continuous inflow is stored, and worked off in a few hours per day. This operation mode causes water oscillations in the downstream river bed, which can create ecological problems and human safety risks near the river. For capacity factor see Box 7-2.

Figure 7-6: Recommended design discharges for run-of-river HPPs for a flat FDC (blue line) and a steep FDC (red line) providing equivalent average flow



Source: FICHTNER

7.2.4 Hydraulic head

Box 7-2: Capacity factor

Unlike thermal power plants—due to stochastic nature of hydrology, installed HPP capacity is available only when the design discharge is available at the intake.

$$f_P = \frac{\textit{yearly energy production}\left[{}^{MWh}\!/_{year}\right]}{\textit{installed}\ \text{capacity}\,[\text{MW}] * 365\left[{}^{days}\!/_{year}\right] * 24\left[{}^{hours}\!/_{day}\right]}$$

The capacity factor (also called plant factor or load factor) is an important parameter to quantify power plant availability; it is calculated as shown in the following equation.

Capacity factors of run-of-river hydropower plants should range from 40 to 70 percent, and 20 to 40 percent for storage HPPs, depending on installed capacity.

Besides the discharge, available hydraulic head is the most important parameter to determine HPP potential energy output; it mainly depends on HPP site topography. Two categories of head—*gross* and *net*—are distinguished for energy generation (see Figure 7-7).

Gross head is the difference in altitude available for energy generation. Depending on the type of turbine gross head is equal to the following:

- *Francis turbine/Kaplan turbine:* the altitude difference between the upstream (head) and downstream (tail) water levels.

- *Pelton turbine:* the altitude difference between upstream water level and the center point of the turbine runner.
- *Cross-flow turbine:* Cross-flow turbines are usually equipped with a draft tube but cannot use the full vertical distance between the turbine runner and the tailrace water level. The gross head is equal to the vertical distance between the upstream water level and the runner center point *plus* 2/3 of the distance between the runner center point and the tailrace water level.

Net head is equal to gross head minus the hydraulic losses of the waterways (Figure 7-7). Friction losses and local hydraulic losses mainly depend on the square of flow velocity—the lower the waterway velocities, the lower the losses. Therefore, net head depends on the discharge and reaches its minimum along with maximum discharge.

Depending on the type of hydropower scheme (run-of-river or HPP with storage reservoir) the upstream level, and the tailwater level are subject to fluctuations. For storage HPPs, upstream water level fluctuations are more important and for run-of-river plants downstream fluctuations are more important because for them usually the upstream water level is maintained constant. That means gross head fluctuates.

The downstream water level depends on the *tailwater rating curve*, indicating the discharge/elevation relation (see Figure 7-8). The higher the discharge, the higher the water level in the riverbed downstream of the powerhouse.

The upstream water level depends on type of reservoir. Typically, in run-of-river HPPs, the upstream water level is maintained at the full supply level elevation. In large reservoirs, the upstream water level depends on the amount of currently stored water, and can vary by 20–30 percent of available head.

7.3 Energy yield prediction

Assessing project feasibility and attracting finance requires a favorable electrical energy yield from the HPP. Energy yield prediction provides a basis for calculating project revenue, and thus project financial viability. The energy yield analysis aims to predict average annual energy output, and annual energy output distribution. The level of accuracy required for an energy yield prediction depends on the phase of project development. For example, a very preliminary indication of energy yield can be carried out using estimated annual average flow data, topographical data from available maps, and estimates of overall efficiency. A more accurate energy yield prediction requires hydrologic data based on long-term flow measurements, topographic data from an accurate terrestrial survey and the specific efficiencies of plant structures.

Figure 7-7: Gross head and net head at a hydropower plant

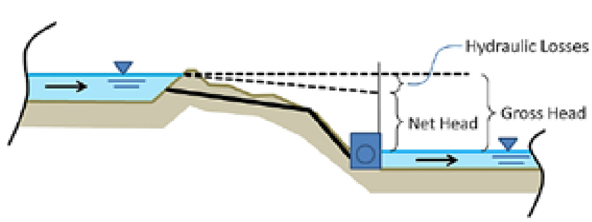
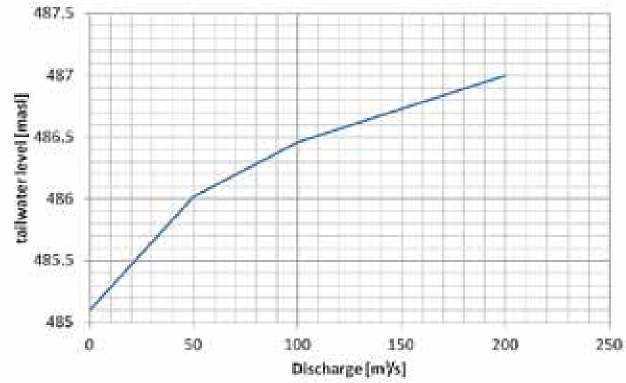


Figure 7-8: Tailwater rating curve



Source: FICHTNER

Energy is the product of work done in a specified amount of time, so HPP energy generation is often expressed in MWh/year or GWh/year, depending on size. It is calculated based on hydrological data, detailed topographical information and HPP design specifications.

Energy production can be calculated based on monthly, 10-day or daily average flow values derived from hydrological data (minimum 15 years of flow measurements). Shorter periods of averaging produce more accurate energy generation results. Results from monthly average values can overestimate energy generation by 10 percent or more.

For run-of-river power plants with a constant upstream water level, energy generation calculations can be done manually (Figure 7-9). For storage power plants, energy generation calculations depend on reservoir operation policy so they are usually simulated with reservoir-simulation software (Figure 7-10).

The energy calculation is carried out based on the power and energy equations found in Section 7.2. Not surprisingly, energy prediction accuracy depends on input data accuracy, therefore the following points should be considered:

- ***Overall efficiency*** *(η):* Turbine efficiency varies according to turbine type, discharge and available head.
- ***Discharge*** *(Q):* More accurate energy predictions result from using more detailed statistical hydrological input data. Daily flow values provide more accurate results than monthly flow values.
  Depending on the type of turbine, below a specified minimum flow (10–40 percent; see Section 7.2.2) the turbine cannot be operated due to technical constraints, which means that energy output is equal to zero.
- ***Head*** *(H):* Net head is used for energy calculation. Because head losses vary and tail water levels fluctuate, net head value depends on discharge. In addition, at storage power plants, net head varies according to the amount of water stored in the reservoir, which influences the reservoir water level.

- ***Forced outage:*** This occurs when an HPP must be shut down due to any type of failure. The percentage of forced outage depends on HPP design and electrical network reliability. Redundancies of equipment and structures reduce the risk of forced outage.
- ***Auxiliary demand:*** HPPs have a specific energy demand. Depending on the HPP size, energy demand lies within the range of 0.5–3.0 percent of annual energy generation. Auxiliary demand should also be considered in an energy generation calculation.

Figure 7-9 shows an energy generation calculation for a run-of-river power plant, carried out based on the flow duration curve (FDC) with average daily values. First, the usable flow, net head and efficiencies are obtained depending on the discharge, and then on their basis daily power and energy values are calculated. Finally, the sum of daily energy values is equal to mean annual energy generation.

The gross head of storage power plants can experience strong fluctuations, depending on reservoir water level. Software can simulate reservoir operation by applying so-called operation rules. The software program considers the given inflow and reservoir storage capacity then simulates power plant operation. The results include reservoir water levels, available head, power output, and energy production for a specified duration.

Figure 7-9: Energy calculation of a run-of-river power plant based on the flow duration curve with daily average values

Design Discharge: QD=57.53m³/s

Gross Head: h=84m

count	Daily Average Flow [m³/s]	Usable Flows [m³/s]	Net Head [m]	Efficiency Turbines [-]	Efficiency Generator [-]	Efficiency Transformer [-]	P Power [MW]	E Energy [MWh]
1	99.38	57.53	81.79	0.89	0.98	0.99	39.80	955.1
2	97.89	57.53	81.79	0.89	0.98	0.99	39.80	955.1
3	96.81	57.53	81.79	0.89	0.98	0.99	39.80	955.1
4	95.74	57.53	81.79	0.89	0.98	0.99	39.80	955.1
5	93.39	57.53	81.79	0.89	0.98	0.99	39.80	955.1
6	90.79	57.53	81.79	0.89	0.98	0.99	39.80	955.1
347	23.24	23.24	83.64	0.72	0.98	0.99	13.35	320.3
348	23.21	23.21	83.64	0.72	0.98	0.99	13.32	319.6
349	23.18	23.18	83.64	0.72	0.98	0.99	13.29	318.9
350	23.07	23.07	83.65	0.72	0.98	0.99	13.19	316.5
351	22.95	0.00	84.00	0.00	0.98	0.99	0.00	0.0
352	22.94	0.00	84.00	0.00	0.98	0.99	0.00	0.0
353	22.71	0.00	84.00	0.00	0.98	0.99	0.00	0.0
354	22.44	0.00	84.00	0.00	0.98	0.99	0.00	0.0
355	22.42	0.00	84.00	0.00	0.98	0.99	0.00	0.0
356	22.17	0.00	84.00	0.00	0.98	0.99	0.00	0.0
357	22.08	0.00	84.00	0.00	0.98	0.99	0.00	0.0
358	22.04	0.00	84.00	0.00	0.98	0.99	0.00	0.0
359	21.81	0.00	84.00	0.00	0.98	0.99	0.00	0.0
360	21.67	0.00	84.00	0.00	0.98	0.99	0.00	0.0
361	21.60	0.00	84.00	0.00	0.98	0.99	0.00	0.0
362	21.16	0.00	84.00	0.00	0.98	0.99	0.00	0.0
363	21.07	0.00	84.00	0.00	0.98	0.99	0.00	0.0
364	20.88	0.00	84.00	0.00	0.98	0.99	0.00	0.0
365	19.37	0.00	84.00	0.00	0.98	0.99	0.00	0.0
					Average annual energy [GWh/year]			243.28
					1 % forced outage			2.43
					2 % auxiliary demand			4.87
					Total annual energy generation [GWh/year]			235.98

Source: FICHTNER

Figure 7-10 shows the results of a simulation that was carried out daily over 13 years. The uppermost window displays gross head fluctuations, which vary by about 11 percent. The middle window displays inflow/outflow, which differ from each other due to reservoir retention. The bottom window displays daily energy generation in MWh/day. To calculate average annual energy production (in GWh/year), average all calculated daily values; multiply the result by 365.

7.4 Seasonal variability / firm capacity

Depending on the region, seasonal variability can be significant due to wet and dry seasons. Figure 7-11 displays mean monthly flow values of a location in central Africa that shows two high-flow periods—May and November. The average November flow is ten times higher than February flow.

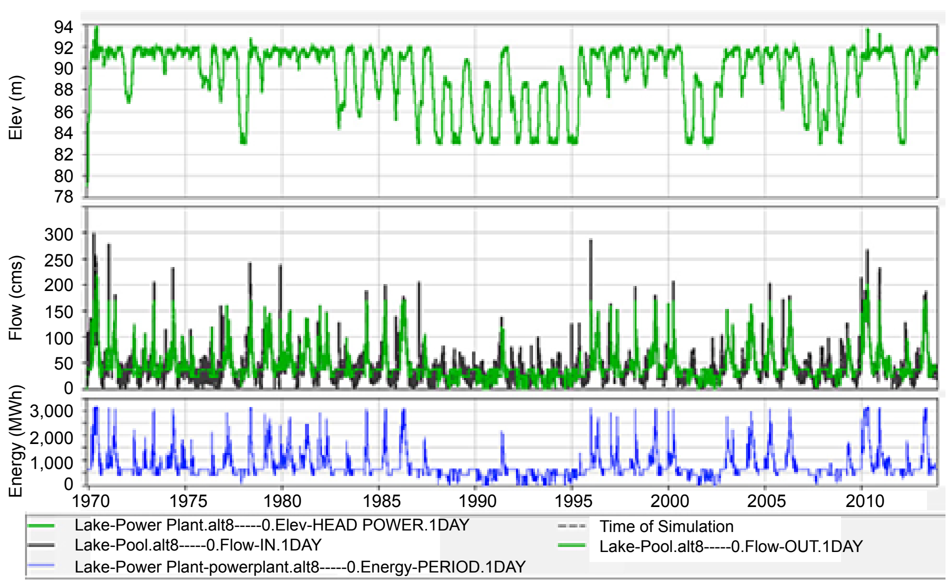
An intense seasonal variability complicates the selection of installed capacity. If the installed capacity selected is too high, higher construction costs could make the HPP inviable. If a lower installed capacity is selected, the HPP cannot fully exploit available water for energy production. One solution to manage variability is to install a reservoir, which can store rainfall during wet seasons and use the stored water during dry periods. This increases total energy output and distributes production more evenly during the year.

The best procedure to select HPP design discharge and storage capacity is to use a financial optimization analysis, shown in Section 7.2.3.

An important parameter to show HPP power availability is *firm capacity,* which is a guaranteed amount of power available during a specified period for production or transmission. For example, if hydropower stations specify that power output will be generated 90–95 percent of the time, this is their firm capacity. Higher firm capacity means higher value of a power station for the energy market. Run-of-river plants depend only on hydrology for their firm capacity; storage power plants can improve firm capacity by storing water.

Figure 7-12 shows the power duration curves of two types of HPP. Energy has been calculated at the same location for (a) a run-of-river HPP and (b) a storage HPP with optimized operation. At the run-of-river plant, firm capacity generated for 90 percent of the year is 11 MW; for the storage HPP, firm capacity is almost double at 23 MW for the same period.

Figure 7-10: Energy calculation of a storage power plant, based on the reservoir simulation software HEC-ResSim provided by the US Army Corps of Engineers



Source: FICHTNER

Figure 7-11: Mean monthly flows of a location in central Africa

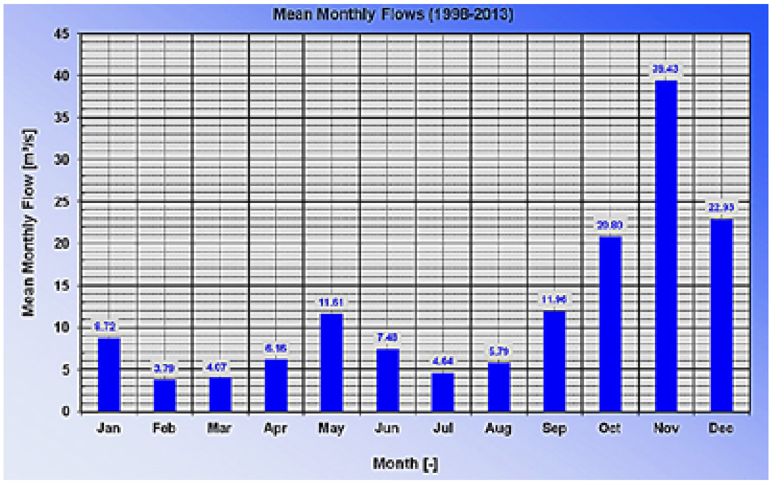
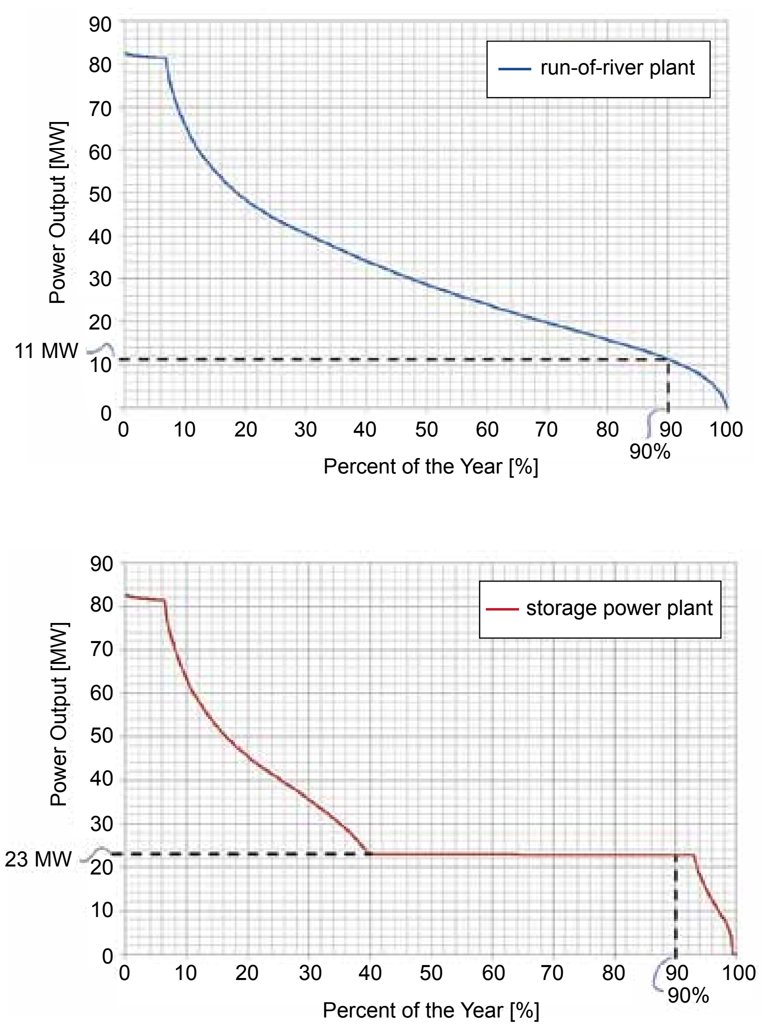


Figure 7-12: Power duration curve of a run-of-river plant and a storage plant



In all countries, HPP authorization requires multiple permits, licenses, and other documents.

Permits and Licensing

8

Typically the hydropower authorization process involves several steps but this varies among countries as to their nature, extent, content, sequence and timing. Other variations might occur related to project size, location, and characteristics according to how they are covered in the national legal framework. For example, Kazakhstan's regulations governing grid connection have shorter deadlines for projects below 5 MW; in Serbia, procedural distinctions exist based on project size because balancing responsibilities differ according to plant capacity (< or > 5 MW). In Montenegro and Macedonia, procedures are shorter for smaller projects because the developer obtains construction permits from the municipality, not the ministry [Merle-Beral 2015].

In all countries, HPP authorization requires multiple permits, licenses, and other documents; these are noted in Table 8-1.

The authorization process might be conducted by a central government agency, with legal, financial, technical and environmental and social inputs from other agencies. Additional agencies, such as those related to preserving cultural heritage, civil aviation security, or military can get involved if project construction or operation affects their jurisdictional area.

In some countries, multiple institutions are involved in the permitting processes, including the energy regulator or the anti-monopoly commission (tariff approval), the ministry of regional development or the ministry of natural resources (land/siting issues), a construction agency (construction permits), the ministry of energy or industry (power sector planning, grid integration), the ministry of environment (environmental permits), and local authorities and grid companies.

Procedures depend on the country of investment and specific project characteristics. Box 8-1 shows licensing procedures in Nepal to illustrate how licensing procedures vary greatly by country. The investor should be thoroughly informed of procedures before making investment decisions; some governments provide guiding documents.

Table 8-1: Typical documentation types required to obtain authorization for HPP construction

Approvals/Licenses	Required procedures; examples
General documentation related to business operation	Business and property register documents
	Taxpayer entity register documents
	Proof of financial capability, non-bankruptcy and legal compliance
Investment license (if applicable)	For example in Uganda, an investment license from the Uganda Investment Authority is mandatory for foreigners who plan to invest over €78,200.
License to import equipment (if applicable)	For example, in Brazil, to import equipment for the construction of RE plants an import license is required (LI, Licença de Importação) according to the Brazilian government's SISCOMEX (Sistema Integrado de Comércio Exterior) guidelines.
Approval(s) from local authorities for the right to conduct business	For example, the Philippines requires a business permit from the municipality or locality where business will be established (Philippine DOE).
Land-use rights	Obtain proof of ownership or usage rights to land. This can include signing a long-term land lease or purchasing the land from a public or private owner. Procedures for obtaining the land use rights differ not only among countries but also between regions/localities within the same country.
	Obtain permission to change use (where each parcel requires authorization for a specific and exclusive land use, e.g., industrial or agricultural); *or*
	Obtain an exemption from the zoning regulations.

(continued)

Table 8-1: Typical documentation types required to obtain authorization for HPP construction *(continued)*

Approvals/Licenses	Required procedures; examples
Consents/permits and other authorizations	Cultural heritage authority permit stating that the land parcel is free of archeological/cultural heritage sites/ objects.
	Civil aviation security permit stating that any power transmission lines to be built by the project will not interfere with the flight routes.
Water usage for production of energy permit	This permit is important given the conflicts that may exist with other water usages (irrigation, drinking water supply, maintaining a sustainable ecosystem). It also covers conflicts related to trans-boundary issues. Royalty payments are common in exchange for the right to exploit water. However, some countries with rich hydropower resources such as Armenia, Georgia and Tajikistan do not require small hydro plants to pay royalties or fees for water use; they require only an authorization/permit from a specialized body. In other countries, it is common to tender concessions of hydropower sites (e.g., Balkan countries), and hydro plants pay a concession fee water use, either a fixed amount or per kWh.
Environmental approvals	Approved Environmental and Social Impact Assessment (ESIA) varies depending on project characteristics and location (please refer to Section 6.5.7)
	Review and approval by the river and/or irrigation authority
	Statements from relevant government agency that the project is not in a protected or environmentally sensitive area.
Procedures specific to renewable (RE) power plants	Energy permit or other authorization from the energy authority confirming that the project conforms to national energy strategy/power development plan (in some countries).
	Grid connection agreement (for on-grid projects). Legislation in many countries stipulates a mandatory interconnection of RE plants to the national grid; grid companies are legally obliged to develop preferential/ simplified/standardized procedures for connecting RE plants. These procedures may be described in the grid code, the distribution code, in both codes, or in a separate document.
	Power purchase agreement (PPA). PPAs with renewable energy plants often include special conditions, such as mandatory off-take, take-or-pay conditions, or guaranteed dispatch/deemed generation clauses.
	Energy license or generation license and/or other approvals are required to operate a power plant.
	Registration as a "qualified/privileged/special/RE" generator and/or other procedures to obtain support (e.g. FiT, fiscal benefits), if applicable. In Uganda, the RE FIT tariff is awarded at the time of the license award. Tariff privilege expires when the license expires. In Serbia and Macedonia, RE developers apply for a status of privileged producers (to become eligible for support) when the development process ends, after having obtained the plant operation permit; however, they may get a *preliminary* status of privileged producer earlier, usually with construction permit.
	Procedures to prove compliance with local content requirements (if applicable). Several countries make local content requirements a condition for granting public support. However, the absence of clear rules on how local content is calculated, reported, monitored and verified, creates substantial uncertainty for investors and can jeopardize the whole support system and deter projects. For example, in Ukraine, local content requirement stipulated in primary legislation could not be applied for a long time because implementing regulations had not yet been established.
	Certification for equipment used. e.g., in Brazil, all technology used for construction of RE plants requires certification from the Brazilian INMETRO (Instituto Nacional de Metrologia, Qualidade e Tecnologia). This certification can be obtained *only* by a company registered in Brazil.
Construction	Construction or building permits, which can include approval of feasibility study or project design documentation by a public authority. Obligatory insurances for construction are usually required.
	Clearances from sanitary, emergency, fire and other authorities. If the site itself or the road to the site is to be constructed in the forest, a permit from the forestry authority can be required.
	Plant commissioning procedures.

Source: FICHTNER, based on Merle-Beral, 2015

Box 8-1: Example Nepal

In Nepal, electricity generation greater than 1000 kW, requires an application to the prescribed officer, accompanied by economic, technical and environmental studies applicable to specific project.

Two types of licenses exist:

- Survey license
- Development license

Survey refers to acts relating to electricity generation, transmission or distribution and acts relating to the feasibility study, detailed engineering design and the works of investigation. Development means construction, operation and maintenance of energy generation, transmission and distribution structures.

First, a hydropower business must apply for a survey license, and after it is issued, the HPP business can apply for a development license.

License application implies the preparation and presentation of documents including the following

- Topographic map of project-site
- Estimated cost and time for project completion
- Necessity, purpose and total length of transmission line
- Estimated number and type of consumers to benefit from the distribution system
- Copy of the company register certificate
- Analysis of environmental effects
- Any potential acquisition or utilization of houses and land

For a development license, an approval letter from the concerned authorities stating that an environmental study has been carried out, such as an Initial Environmental Examination or an Environmental Impact Assessment, and a feasibility report must be submitted, accompanied by a Letter of Interest for the Power Purchase Agreement.

A survey license for electricity is valid for a maximum of five years. A development license for a HPP is valid for a maximum of 35 years. Both can be renewed.

Hydropower projects from 100 kW to1,000 kW need no license. However, the developer must submit an application along with the project-related information to the Ministry of Environment including the following:

- Detailed project description
- Map of project site (main structures must be shown)
- Source and quantity of water to be utilized
- Area of electricity distribution and estimated number of consumers to benefit
- Whether water resources to be utilized have already been utilized by others; if so, supply particulars
- Any other related information

Source: Internal IFC draft documents, courtesy of the South Asia Enterprise Development Facility (SEDF) program, Nepal Business Licenses Inventory Study, Vol II.

8.1 Concessions

Concessions are the starting point for any HPP development. A concession enables a private investment partner to finance, construct and operate a HPP in return for the right to collect the associated revenues for a predetermined period defined in the concession agreement. A concession agreement provides a basis for a public entity to transfer some public rights to a local or a foreign entity to engage in a profit-oriented activity, subject to the terms of the agreement, and in return for paying revenues to the national government or to a local self-government entity for the rights acquired. Essentially there are three types of concessions that are typically awarded through competitive bidding. These include the following:

- ***Concession for goods of general interest:*** The award of a right to exploit goods of general interest (natural resources such as water, minerals, etc.), which may include constructing a new facility or modernizing an existing facility.
- ***Public works concession:*** Awarded for performing public works (same as a public procurement-of-works procedure, except that remuneration comprises only the right to exploit such works, or this right together with payment).
- ***Public services concession:*** same as a public works concession, except that this type of concession is awarded for public services.

8.2 Environmental permits and licensing

Environmental permits and/or licenses are essential for project construction authorization by national authorities (see Box 8-2).

Granting an environmental license or permit normally depends on the elaboration of an ESIA. The nature and level of detail depends on national legislation and project scale, location, potential impacts and other considerations.

If a project is to be financed by IFC it must meet IFC Performance Standards (PS) in addition to complying with applicable national law and national obligations as specified under international law.

This section describes the usual environmental licensing/permitting procedures (Section 8.2.1) and the IFC PS (Section 8.2.3). Every investor receiving funds from the IFC for a development project shall be aware of these requirements.

Box 8-2: Environmental permits/licenses

Definitions of *"environmental license"* and *"environmental permit"* are not globally ascertained.

In **Germany** an environmental license is a general or broad permission from the environmental authority to build a project involving several sectoral environmental permits (water usage permit, air emissions permit, land use modification permit, etc.) For some countries, the concepts of license and permit are used interchangeably. For example, the EIA Guidelines for the Energy Sector of **Uganda** mention that the projects shall be "permitted or Licensed," whereas the national Guide to the EIA Process mentions only a "permit." In **Portugal** "environmental license" is a term that applies only to licensing industrial sources (a fixed technical unit responsible for activities such as energy production, chemical production, foundries and waste incineration). For environmental authorization, the environmental authority issues an "Environmental Impact Declaration" imposing conditions under which another ministry shall issue a construction license.

The concepts of environmental license and permit must be considered in the country of investment.

8.2.1 National permitting and licensing requirements

Typical procedures for obtaining an environmental permit or license are summarized in Figure 8-1 below. However, each country will have its own procedures to be taken into consideration before applying for an environmental license/permit.

The scheme shows that obtaining an environmental permit and/or license depends on an elaborated and approved environmental and social impact assessment (ESIA). An ESIA aims to ensure that any project will incur the least negative environmental and social impacts on its area of influence. The ESIA includes strategies to enhance project benefits and mechanisms to compensate for any negative impacts that cannot be mitigated. The ESIA is an ongoing process, undertaken concomitantly with project technical planning and taken into account in project financial planning. See Section 12.

The ESIA shall comply with national regulations and any international agreements or treaties to which the country is a signatory or party. Ideally, national authorities will provide template documents. Examples of relevant international agreements include the following:

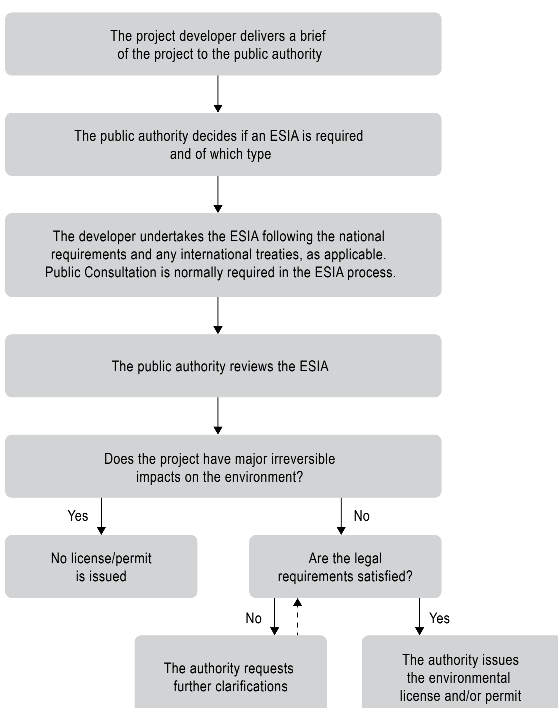
- The Convention on Biological Diversity (1992): 193 parties, 168 signatory parties
- The Ramsar Convention on Wetlands (2000): 168 contracting parties, 2,181 designated Wetlands of International Importance
- The Aarhus Convention on Access to Information, Public Participation in Decision-Making Processes and Justice in Environmental Matters (2001): 47 parties
- The UN Convention to Combat Desertification (1997): 195 parties, 114 signatory parties

International agreements commit the signatory country to apply measures necessary to comply with agreement principles. Ideally, national legislation has been elaborated to include the principles of international conventions and standards. Measures might include the prohibition of construction on protected areas or wildlife trafficking, and the obligation to ensure public consultations, among others. International agreements also bind national authorities to ensure that project developers or investors meet their obligations and that the project complies with all requirements.

Often, international consultants collaborate with local consultants to develop the ESIA. In many African, Asian and Middle-Eastern countries, the ESIA is accepted only if undertaken by environmental experts licensed by the national environmental authority. This approach aims to achieve quality standards for ESIAs, based on local experts' more profound knowledge of national legislation, unfettered access to national data, ability to carry out public consultations in the national and/or local language, and access the proposed project site, among other advantages in experience and expertise. This approach also develops local capacity.

Box 8-3 and Box 8-4 provide examples of environmental licensing procedures.

Figure 8-1: Typical process for obtaining an environmental license and/or permit



Source: FICHTNER

Box 8-3: Example Malaysia

In Malaysia, a developer must determine whether the project constitutes a "prescribed" or a "non-prescribed" activity.

If the project is a non-prescribed activity, the developer must consult the Department of Environment (DOE) for consideration and advice on site The site suitability evaluation assesses whether the site is compatible with the gazetted structure/local plans, surrounding land use and provision of set-backs or buffer zones. This step determines whether a license will be issued for the project based on whether construction will be allowed on that site. If not a new site must be found.

If the project is a prescribed activity, a Site Suitability Evaluation is needed but it shall be followed by an Environmental Impact Assessment, either a Preliminary EIA or Detailed EIA, based on the decision of the responsible authority and depending on the magnitude of impact expected from the project. The EIA must be conducted by DOE-registered individuals.

HPPs are classified as "prescribed" activities under the either or both of the following circumstances apply:

- Dams are over 15 meters high and ancillary structures cover a total area in excess of 40 hectares;
- Reservoirs have a surface area in excess of 400 hectares.

HPP projects, including the construction of dams or impounding reservoirs with a surface area of 200 hectares or more, are classified as a prescribed activity, for which a Detailed EIA is necessary.

Source: Department of Environment of Malaysia, 2010

Box 8-4: Example Mozambique

According to Decree 45/2004, any public or private activity that directly or indirectly affects the environment must obtain an environmental license before its initiation. To obtain this license, the following must be observed:

1. The Ministry for the Environmental Coordination (MICOA) classifies the project in:

- Category A: the project shall be subject of a full EIA
- Category B: the project shall be subject of a simplefied EA
- Category C: the project does not need to be subject of an EIA

2. For Category A and B projects, the proponent shall undertake a full EIA or a simplified EA, respectively.

3. If the requirements are fulfilled and the project has no major irreversible impacts on the environment, the environmental license is issued. For Category A and B projects, license is issued after analysis and approval of EIA/EA.

Source: Impacto

A license/permit imposes specified environmental and social responsibilities throughout the project lifespan. Typically, these include an obligation to implement mitigation measures as defined in the approved EA, and to meet requirements for monitoring and auditing project construction and operation, accompanied by regular reporting to the authorities.

Typically national authorities charge a fee to issue an environmental license/permit. For example, in Mozambique this fee is 0.2 percent of total project cost; such costs shall be taken into consideration during project financial planning.

In addition, most environmental licenses or permits remain valid for a limited time, implying that project construction shall start within a specified maximum time frame (e.g., in Jordan, one year). This aims to ensure that conditions in the project area at the commencement of project construction remain unchanged from the conditions on which the EA was based.

8.2.2 Water licensing

Typically, project developers must obtain a water usage permit from the ministry/authority responsible for water management operations; this allows the use of facilities and installations governed by water rights law, establishes requirements that must be met during construction, and is a legally binding precondition for obtaining a construction permit.

In many countries, developers are required to submit the following documents and information to obtain a water usage permit:

- Basic design, including geodetic survey
- Hydrological data
- Report on revised technical documents

8.2.3 IFC Performance Standards

The IFC Performance Standards (PS) lay out requirements to be met throughout the life of an IFC investment by the party responsible for project implementation, or the recipient of IFC financing.

A project developer shall undertake an environmental and social impact assessment (ESIA) to establish measures for compliance with the applicable PS, to ensure that the project will minimize negative impact on the environment and social conditions in the project area of influence.

The nature and level of detail of the ESIA depends on the nature, scale, location and expected impacts from project construction and operation.

Also, national requirements shall be observed, including those imposed by applicable international law and any treaties to which the country is a signatory or party.

The following paragraphs provide a brief description of each of the eight IFC Performance Standards.

PS 1: Assessment and Management of Environmental and Social Risks and Impacts. PS 1 states the need to conduct an assessment for a new project, and to establish and maintain an Environmental and Social Management System (ESMS). A list of the required content is as follows:

- Applicable laws and regulations
- Identification of risks and impacts
- Significance of impacts, including those related to greenhouse gas emissions, when applicable
- Area of project influence
- Identification of any disadvantaged groups
- Mitigation, performance improvement, monitoring and capacity building/training measures
- Emergency plans
- Procedures for engaging all project stakeholders and disclosing information to them, in particular, indigenous people
- Establishment of external communications strategies and grievance resolution mechanisms for project-affected persons

PS 2: Labor and Working Conditions: PS 2 aims to ensure worker safety and protection of rights, including a safe and healthy work environment, equal application of worker terms and conditions regardless of origin, and the right to form worker organizations, among others.

PS 3: Resource Efficiency and Pollution Prevention: PS 3 aims to ensure that the project employs technologies best suited to efficient and effective resource use, and to avoid or minimize pollution to air, water and land.

PS 4: Community Health, Safety and Security: PS 4 aims to address project risks and impacts on communities exposed to project activities, equipment and infrastructure. This PS states the requirement to design, build, operate, and decommission structural elements according to Good International Industry Practices (GIIP). Competent professionals should be in charge of design and construction, and, in high risk situations, external experts should review throughout the stages of the project.

PS 5: Land Acquisition and Involuntary Resettlement: PS 5 aims to minimize or avoid negative impacts of project implementation resulting from economic and physical displacement, land acquisition, or land-use restrictions. In fact, PS 5 aims to restore or improve pre-project livelihoods and standards of living of project-affected persons.

PS 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources: PS 6 requires that the project includes measures to protect and conserve biodiversity, sustainably manage living natural resources, and maintain ecosystem benefits. Investors will include conservation among their development priorities.

PS 7: Indigenous Peoples: PS 7 recognizes that indigenous peoples (IP) can be marginalized due to sometimes tenuous economic, social and legal status and limited capacity to defend their rights and interests. For this reason, PS 7 specifies that project planning and implementation shall ensure full respect for IP rights, dignity, aspirations, livelihoods, culture, knowledge and practices.

PS 8: Cultural Heritage: PS 8 aims to ensure that the project will have no negative impacts on cultural heritage in the project area, including tangible moveable or immovable objects, natural features, or cultural knowledge, among others.

Box 8-5: The Equator Principles

The Equator Principles obligate signatory financial institutions to implement a set of principles in their internal environmental and social policies, procedures and standards for financing of projects. This means that the signatories will refuse financing to projects. This means that the signatories will refuse financing to projects that do not respect these principles.

Concerning the environmental standards under which a project shall be planned and implemented according to an Environmental Assessment, as defined by the EP the following conditions shall apply:

- For projects located in Non-Designated Countries, the assessment process evaluates compliance with the IFC Performance Standards on Environmental and Social Sustainability (applicable at the time) and the World Bank Group Environmental, Health and Safety Guidelines (EHS Guidelines).
- For Projects located in Designated Countries, the assessment process evaluates compliance with relevant host country laws, regulations and permits that pertain to environmental and social issues.

Source: Equator Principles

The Performance Standards are not mandatory to obtain an environmental license from national authorities, but they are essential for IFC financing, and are the technical standards to which the Equator Principles (EP) refers for projects in many countries and respected by the 80-member financial institution. More information is provided in Section 12.3.

The PS are de facto the private sector E&S benchmark for international investors and are often used outside of the context of direct IFC involvement in a project.

The Performance Standards reflect principles recognized by other international institutions such as the Asian Development Bank, the European Bank for Reconstruction and Development, the Inter-American Development Bank and the African Development Bank. All these institutions have their own standards which are very similar in approach and content to those of IFC.

The HPP construction should be managed according to general construction project management best practices—the project shall be constructed to specifications for quality, time and budget.

Construction

9

The HPP construction should be managed according to general construction project management best practices—the project shall be constructed to specifications for quality, time and budget. Furthermore, social and environmental impacts and human health and safety must be considered at all times. Important components of construction project management include contract strategy, construction program and scheduling, planning and task sequencing, and risk and cost management.

9.1 Form of contract

Typically, a project developer creates three or four separate contracts: civil construction; E&M equipment; grid connection; and penstock (often included under civil construction).

For each of the above, an engineering, procurement and construction (EPC) contract is tendered and signed. Under the EPC contract, the contractor designs the installation, procures materials and builds the project, either directly or through subcontracting. Typically, the contractor carries project risk for schedule and budget in return for a fixed price (lump sum).

Coordination among multiple EPC contractors (interface management) is often the responsibility of the developer or the developer's engineer. This critical oversight and coordination task requires a very experienced engineer because oversight responsibility begins with the study and planning phase and continues until plant commissioning.

It is uncommon to assign a general contractor to carry overall responsibility for plant engineering. In such case however, there would be less coordination from the developer side, but the general contractor would have to be supervised, including applying principles similar to those used for individual EPC contractors.

For international projects the Fédération Internationale des Ingénieurs-Conseils (FIDIC) provides standard contract forms, referred to as the *red book*, *yellow book*, *silver book* and *green book*, depending on contract type (Figure 9-1). The FIDIC contracts are written in formal legal English and are drafted based on common law background.

The FIDIC *silver book* pertains to EPC and turnkey projects, generally applicable to HPPs. The silver book is a template for a lump-sum contract and assigns risk to the contractor, and offers greater certainty to the employer concerning project cost and completion date. There is no engineer; the employer covers engineering responsibilities.

Figure 9-1: FIDIC standards

Source: FICHTNER

9.2 Scheduling

During HPP project construction, a comprehensive schedule is crucial; using a professional program for this task is recommended. At a minimum, the schedule should include the following components:

- Tasks and durations
- Restrictions placed on any task
- Contingency of each task
- Milestones and key dates
- Interdependencies among tasks
- Parties responsible for tasks
- Project critical path
- Actual progress against plan

For an HPP project the schedule should include levels of detail for each construction lot:

- Site access/site clearance
- Civil works construction
    - Dam and diversion works
    - Headrace/penstock
    - Powerhouse
- Manufacturing and transport of E&M equipment
- E&M installation
- Switchyard and connection to the grid
- Commissioning and testing

The construction schedule should be completed during the detailed design phase. Each scheduled task will be worked out in detail and the influence of the tasks on one another should be investigated to emphasize key deadlines that have an impact on the overall construction period.

The schedule will consider time contingencies and delays due to weather or other unforeseen circumstances, and will highlight the critical path.

The procurement schedule should incorporate a focus on items that require a long manufacturing lead time (such as E&M equipment or penstock) to ensure they are ordered and delivered on schedule. This tactic will also highlight any timing issues between delivery and construction, or a need for on-site storage.

Milestones are goals that are incorporated in the contract that are connected to contractual obligations, advance payments or penalties. Milestones should be highlighted in the schedule to assure on-time completion.

9.2.1 Planning and task sequencing

Successful task planning and sequencing enables finalizing the HPP project on schedule. In particular, task *sequencing* ensures that the execution of subsequent tasks is possible. For example, mechanical and electrical equipment can be installed only *after* completion of powerhouse civil works. Successful sequencing also requires timely ordering of manufactured equipment, and anticipating and scheduling time for transport to the site. Equipment and parts that arrive too early must be stored on site, which increases risk.

Typically, an HPP project critical path is as follows: access roads, penstock construction, tunneling, E&M equipment manufacturing, and connection to the grid. Critical issues can vary from project to project.

To develop a logical and efficient sequence, each task category should be broken down into a series of sub-tasks, accompanied by an assessment of inputs required for each task, especially those requiring interfaces.

9.2.2 Risk management

Risks associated with HPP construction should be identified and considered during the whole process. Each risk should be evaluated in terms of (a) *probability* and (b) *consequences*. Contingency plans should be designed and established. The potential impact of any realized risks should be incorporated in project planning and scheduling, in particular those that could affect the project budget and deadline.

9.2.3 Stakeholder management

Stakeholder management is crucial for HPP projects. Stakeholders should be consulted and involved from the very beginning of the planning phase; local concerns must be assessed and a mitigation plan established. Before construction begins, stakeholders should have been informed about what to expect, and the developer must have plans in place to mitigate any negative impacts on the population and/or the environment.

9.2.4 Cost management

The HPP project viability is influenced by construction duration. Neither energy generation, nor revenue generation can be initiated before HPP commissioning. During construction an HPP is simply incurring costs so a shorter construction period can reduce the payback period. In addition, the construction period requires careful cost management, and therefore close attention to the construction schedule and payment structure.

The payment structure depends on the contract type. For EPC contracts the agreed lump sum is split into several payments connected to construction milestones in the contract. As mentioned, typically for HPPs, civil works and E&M are awarded separately. The ratio of civil costs to E&M costs are around 50/50 to 60/40. The payment structure for each is different and can vary from case to case.

The payment structure can be arranged as shown in the following points (see also Table 9-1):

- **For civil works** the advance payment is in the order of 10 percent. Throughout the construction period, 80 percent of the lump sum is disbursed through regular payments connected to specified construction milestones; 10 percent of the lump sum is paid upon HPP handover.
- **For E&M equipment** there is a payment of 30 percent in advance; 50 percent of the lump sum is paid out in increments as delivery is taken for single pieces of equipment; 20 percent is paid on acceptance.

Table 9-1: Potential payment schedule for EPC contracts: civil works/E&M

Payment	Due upon	% of Contract	
		Civil	E&M
Advance payment	Commencement date	10	30
Interim payments	Connected to milestones	80	50
Final payment	Handover	10	20

Source: FICHTNER

Typically, the engineer prepares an overall commissioning schedule, which covers all hydropower scheme elements including water retaining structures, power waterways, hydro-mechanical equipment, transmissions facilities, ecological appurtenances such as fish ladders, ecological flow devices, and so forth.

Commissioning 10

Hydropower scheme commissioning requires thorough understanding of the power generation process "from water to wire." Many fields of expertise are required during the commissioning phase, plus careful coordination among various activities to ensure project safety, reliability and longevity.

Prior to commencement of the commissioning tests, all required documents such as quality certificates, test procedures, results from equipment installation tests, and all earlier tests must be made available to the responsible lead commissioning engineer.

10.1 Commissioning

10.1.1 Dry tests

After installation, all equipment is first tested in dry condition to verify basic functionality.

Mechanical and hydro-mechanical tests shall confirm that the assembly has been carried out correctly, that parts move freely as required, that guides and bearings are within tolerances, that controlling servo-motors achieve the required physical and timing strokes, and so forth.

Electrical component tests shall confirm that the wiring connections conform to electrical schematics, and the operation of each controller, switch contactor, relay and other control devices (in particular correct operation of all limit switches) conform to specifications. Furthermore all circuits, interlocks, protective devices and operational sequences shall be tested to ensure correctness. Start-up and shutdown sequences must be run through, and input signals for the control logic must be artificially simulated, such as water pressure or the rotational speed, which are unavailable in dry conditions.

The following is a general guide to a minimum of the measurements and tests to be performed before, and during start up.

10.1.1.1 Hydro-mechanical equipment

- Perform visual inspection and dimensional checks
- Measure gate operational speeds
- Check hydraulic system operating pressure
- Check manual operation of hydraulic power unit
- Check accuracy of indication, limit setting and alarm signal from local and main control board, etc.
- Check limits of travel

Frequently, dry tests on the hydro-mechanical equipment need to be carried out well in advance of commissioning generating equipment for projects with storage reservoirs or daily storage ponds. This is because dry tests must be performed *before* reservoir impounding and *before* the power waterways—tunnels and penstocks—are filled. On run-of river projects, dry tests must be performed before filling the construction pit and removing coffer dams.

10.1.1.2 Mechanical equipment

- Perform visual inspection and dimensional checks
- Check alignment of ready-assembled turbine and generator shaft in dry conditions, according to NEMA or IEEE Standard limits
- Check bearing clearances
- Perform hydrostatic pressure and tightness tests for all equipment containing or carrying water, oil and compressed air
- Perform distributor dry test and measure wicket gate openings
- Perform wicket gate timing tests
- Perform main inlet valve timing tests
- Conduct governor logic, start-up and shut down sequences in dry conditions; check interlocks, indications and characteristics
- Perform operational tests on all turbine auxiliary equipment, including calibration of related electric control instruments; check for correctness of wiring and piping
- Check alarm and protection devices, verify alarm and tripping settings of all supervisory instrumentation

Some dry tests on mechanical equipment have already been conducted as an integral element of equipment installation. Typically clients or a client representative witness the tests;

test records shall be integrated into the commissioning log as evidence of the settings and potential for final adjustment during final commissioning tests.

10.1.1.3 Electrical equipment

- Perform visual inspection and dimensional check
- Check stator bore for roundness
- Checking air gap uniformity
- Check alignment of ready-assembled turbine and generator shaft.
- Check all bearing clearances
- Check entire generator cooling system
- Perform hydrostatic pressure and tightness tests on all equipment containing or carrying water, oil and compressed air
- Check brakes during braking and during lifting operations
- Measure stator-winding DC resistance
- Measure insulation resistance of stator winding and determine polarization factor
- Conduct AC high voltage withstand test of stator winding
- Measure stator-winding insulation resistance
- Measure rotor-winding DC resistance
- Measure rotor impedance
- Conduct AC high voltage withstand test of rotor winding
- Measure rotor-winding insulation resistance
- Perform operational tests on all generator auxiliary equipment, including calibration of related electric control instruments; check for correctness of wiring and piping
- Check alarm and protection devices, verify alarm and tripping settings for all supervisory instrumentation
- Perform tests on excitation system
- Perform functional test of fire-protection system

Similar to mechanical equipment, some dry testing has already been carried out and recorded during equipment installation; test results shall be integrated into the commissioning log.

10.1.2 Wet and load tests

Pre-conditions for wet and load tests on generating equipment are that water-retaining structures have been inspected, tested as far as possible in dry, and are ready for operation. Reservoir impounding, coffer dam removal, power waterway filling, fish ladder operation, and ecological flow-device operation, require detailed planning and coordination with the individual steps of the equipment commissioning process.

Preparatory works on an HPP before performing the first wet tests can be very time-consuming and resource-intensive and involve specialized engineering expertise not directly associated with power generation. For example, during reservoir impounding, ground water level measurements in the project surroundings must be carried out; leakage and deformation of dams and other civil structures such as pressure tunnels must be measured, observed and recorded, and so forth. In addition, the ecological impacts of project commissioning must be observed and possibly mitigated by implementing options such as deforesting the reservoir area, relocating wildlife, or rescuing archeological treasures.

Moreover, transmission line facilities and interconnecting switchyards must be operational to evacuate power to the electrical grid. Most transmission line facilities are under planning and operational authority of a regional or national network distribution company, rather than a direct part of the HPP. Therefore, advance cooperation and coordination with the grid operator is necessary for smooth and continuous commissioning of power generating equipment.

For equipment directly associated with power generation, the tests listed below are typically carried out.

10.1.2.1 Hydro-mechanical equipment

- Check water leakage from closed gates and emergency closure valves
- Conduct pressure tests on tunnels and penstocks
- Conduct discharge tests on regulating and flow-controlling gates

Some tests, such as discharge tests on spillway gates or bottom outlets, depend on available water resources and may have to be scheduled independently of commissioning the main generating equipment, during the correct hydrological season.

10.1.2.2 Generating equipment, electrical and mechanical auxiliaries

Operational tests on the main generating and auxiliary equipment under *wet* conditions are either categorized as *load* or *no-load* tests.

No-load tests: Generating units are rotating at synchronous speed but not electrically connected to the network. One primary objective is to verify that the mechanical installation of the coupled turbine/generator unit is sound with respect to bearing temperatures, balancing of rotating parts, mechanical vibrations, and behavior under over-speed conditions, among others. Other objectives include electrical testing, such as excitation system tests.

Usually the following tests are part of the speed-no-load testing phase:

- Check start-up/shutdown sequence, including mechanical braking
- Conduct initial mechanical run, including over-speed test.

- Conduct mechanical run for bearing-temperature stabilization
- Measure shaft run-out (eccentricity)
- Measure vibration to determine general vibration level and assess balance of assembled rotating equipment
- Conduct functional test of generator-protection relays
- Conduct functional test of excitation system during no-load running
- Measure short circuit and no-load curves
- Determine generator reactance and time constants
- Measure shaft voltages
- Synchronize with grid system

Load tests: Generating unit performance is verified; measured values are compared to performance guarantees specified in the supply contract and/or in the Power Purchase Agreement (PPA) with the grid operator.

Typically the following checks are performed as part of the load test phase:

- Conduct load-rejection tests on one generating unit at a range of load steps, including overload, to check response of turbine governor and excitation system (AVR) under load conditions (typical load steps are 25, 50, 75, 100 and 110 percent of design load)
- Conduct reactive capability test
- Conduct power system stabilizer test
- Energize transmission circuit
- Measure V-curve characteristic
- Check temperature rise and power output
- Measure vibration

There are many other detailed tests on the governor and excitation system response during loading and off-loading of the generating units; also, measurements of generator electrical characteristics under load, tests on generator and transmission system protection under load conditions, etc.

If there are several units, the following tests are performed for joint operation:

- Perform simultaneous load rejection test of all generating units operating at maximum load to check safety device responses and confirm that pressure rise in power waterways, and the speed rise of generating units remains within contract-imposed limits
- Perform active power sharing
- Perform reactive power sharing
- Stabilize power system

10.2 Tests on completion, post-connection acceptance testing, long-term performance and reliability monitoring, hand-over documentation

10.2.1 Performance testing

On larger generating units (>5 MW), field performance tests are often carried out at the end of the commissioning period to verify turbine hydraulic efficiency and generator electrical efficiency.

A field acceptance test in accordance with IEC 60041 to verify turbine efficiencies, and an index test are performed on at least one turbine. Individual losses are measured to determine generator efficiency on a minimum of one generator.

For smaller machines, on-site efficiency testing is too costly to justify; instead, performance guarantees are verified by simple power measurements, without analyzing efficiencies of individual generating unit components.

10.2.2 Trial operation and reliability run

Immediately upon completion of satisfactory commissioning Test-on-Completion, the trial operation and reliability run shall commence.

The duration of the trial and reliability run varies widely with the size of the project and adopted commercial terms and conditions. For small projects, 3-10 days of continuous operation may satisfy requirements; for large projects, 30 days per unit are common.

During the trial run, generating units and all associated equipment shall be subjected to normal operation; generating units are connected to the network for power supply at a range of loads and as required. Proper functionality and readiness for commercial operation of the entire installation shall be demonstrated by this operation.

Minor adjustments and fine-tuning of parts might be carried out during the trial run, if they do not interfere with equipment operation.

If any defects revealed during the trial and reliability run indicate that operational reliability and readiness are not fulfilled, the trial run must be cancelled, re-started and completely repeated in a later stage after all defects have been rectified.

10.2.3 Hand-over documentation

When equipment or equipment parts have passed specified tests, the employer will provide the contractor with a certificate, or endorse the contractor's certificate to indicate endorsement.

All tests carried out during the installation period must be accompanied by comprehensive reports that include description of test, tools and gauges used, data log readings, admissible values for readings, evaluation of results, and so forth to allow full reconstruction of testing and results later.

The commissioning report shall include all test results, diagrams, settings and characteristic systems data.

10.2.4 Commissioning planning, organization and cost

Typically, the engineer prepares an overall commissioning schedule, which covers all hydropower scheme elements including water retaining structures, power waterways, hydro-mechanical equipment, transmissions facilities, ecological appurtenances such as fish ladders, ecological flow devices, and so forth. Engineers define commissioning sequences of major project elements and time blocks required for commissioning each. The contractor works out detailed commissioning procedures and scheduling.

The commissioning organization requires a clear hierarchy, with overall responsibility assigned to a single entity (or person). Each step of commissioning must be thoroughly documented in the form of test records and protocols. Major tests, in particular those verifying contract-specified values such as generating equipment performance guarantees (power, efficiency, pressure rise, speed rise), tightness, opening and closing times of gates and valves, crane hoisting capacity and speeds, HVAC system efficiency, and so forth, must be witnessed and signed off by the client or his representative. Rigid procedures must be followed when a project element under the responsibility of one contractor must be turned over for another contractor to use. Use completion and readiness must be recorded and signed off by the responsible party. Some examples for turnover points during equipment commissioning include the following:

- After tightness test/pressure testing of power waterways, the turbine contractor may commence wet testing.
- After completing no-load generator electrical tests, the generator contractor must confirm readiness for synchronization with network and load tests. As a precondition, switchyard and transmission line contractor(s) must confirm that transmission facilities are tested and ready for operation.

For the client, the easiest and legally simplest way to carry out commissioning is under an EPC contract; the EPC contractor is solely responsible for coordinating commissioning and turning over the works to the client as a whole.

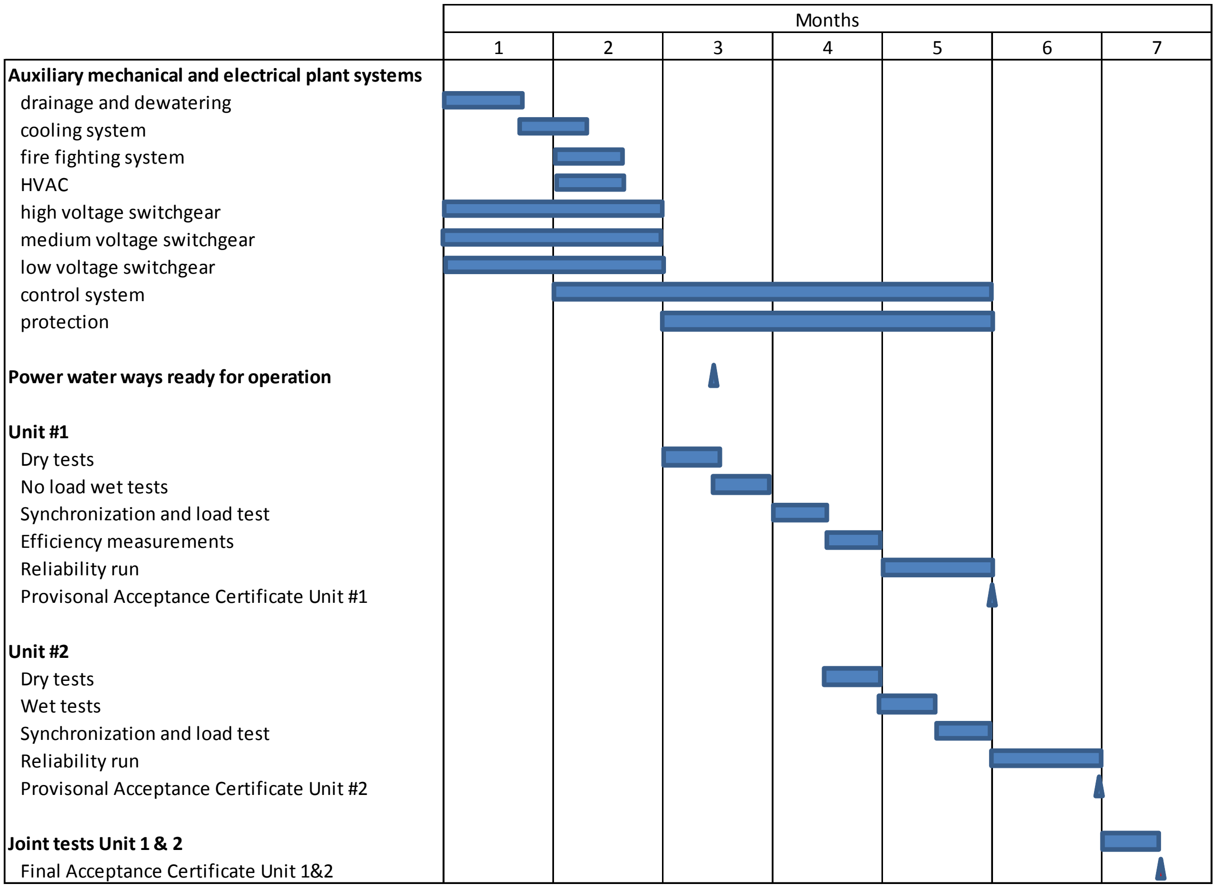
Commissioning time depends on the size and complexity of each project. For small projects with a capacity of a few hundred kW, the commissioning period may be only a few days since most components can be shop-tested before shipping and installation and only a small number of interferences and tests must be carried out on site. For large hydro projects with hundreds or thousands MW capacity and multiple generating units, commissioning may take several months to several years.

The schedule on the following page (Figure 10-1) shows the commissioning schedule for electro-mechanical plant equipment of a medium-head project with two 150 MW generating units.

If the project has multiple identical units, power and efficiency performance tests are normally carried out on only one unit. But any indication of potential problems with achieving contractual guarantees could require performance testing on all units to establish a basis for applying performance penalties.

Commissioning costs depend on the size and complexity of each hydro project; it is impossible to provide figures for guidance. Commissioning cost is a separate item in project price schedules but the numbers given are not representative of actual costs; contractors tend to maximize the share of total costs to the delivery to optimize cash flow.

Figure 10-1: Commissioning schedule



Source: FICHTNER

Operation and maintenance refers to all of the activities needed to run a HPP scheme, except for construction of new facilities.

Operation & Maintenance 11

Maintenance work aims to ensure the highest availability and reliability of power generation equipment and civil structures at optimum cost.

The economic operating life of a hydropower plant could be 70-100 years, which would include rehabilitation of several components. Many hydropower plants that came into service at end-19th Century remain in operation today, although some components may need rehabilitation or replacement.

The average life expectancy of plant parts and systems under normal conditions of operation and maintenance are summarized in Table 11-1 below. These are *average values* and depend on site-specific conditions such as water quality, sediment load, climatic conditions, operational mode (number of starts, stops, operating hours), among others. Time periods listed in the table are a general guide to assess maintenance efforts and the need for larger rehabilitation works.

Table 11-1: Average life expectancy for plant parts and systems

Plant part or system	Expected useful life (years)
Main generating equipment; turbine equipment other than runners; generator, generator/motor; governor; excitation system; main inlet valves.	40
Turbine runners	10
Power transformers	40
High voltage switchgear and switchyard equipment	40
Medium voltage switchgear	30
Low voltage switchgear	30
Control and protection system, remote control, SCADA, communication equipment, metering	20
Plant auxiliary mechanical and electrical equipment (drainage and dewatering pumps, cooling system, compressed air system, ventilation and air conditioning system, AC/DC power supply, emergency diesel generator, etc.)	30
Transmission lines	70
Penstocks, gates, stoplogs, trash racks	70

Source: FICHTNER

Operation and maintenance refers to all of the activities needed to run a HPP scheme, except for construction of new facilities. Since costs associated with maintenance work represent a significant share of total operational costs, proper O&M planning is crucial for long-term economic HPP operation.

For the above-mentioned components, some replacements are classified as *routine maintenance costs* and others (e.g., power transformers) are classified as *major investment* (rehabilitation).

A successful O&M regimen begins during the early planning stages of each project. Future O&M staff should have access to training opportunities in manufacturer facilities during the manufacturing process, in particular during shop assembly and testing. To the greatest extent possible, plant staff shall participate in site installation, commissioning and testing.

On larger projects, contracts often specify that the E&M supplier shall be on-site for the duration of the guarantee period, to conduct trouble shooting on critical control, protection and excitation systems. On smaller projects, permanent on-site manufacturer presence would be uneconomical but software-based control and monitoring systems allow remote maintenance, diagnostics, trouble shooting, parameter adjustments, and so forth.

An efficient system for managing spare parts is essential to maintain highest availability and plant reliability. Spare part inventory must be optimized to minimize costs and maximize plant availability by avoiding prolonged forced outages.

Detailed, comprehensive and clearly structured O&M Manuals are an essential component of an efficient O&M system.

11.1 Types of maintenance work

11.1.1 Scheduled (preventive) maintenance

Preventive maintenance (PM) aims to prevent failures (forced outages) by following routine and comprehensive procedures on a regular schedule based on elapsed time or meter readings. The objective is fewer, shorter, or more manageable outages.

Major advantages of preventive maintenance include the following:

- Facilitates budgeting, planning, and resource leveling
- Prevents most major problems; reduces forced outages, reactive maintenance, and overall maintenance costs
- Provides assurance that equipment is maintained
- Easily understood and justified

Drawbacks of preventive maintenance include the following:

- Time-consuming and resource-intensive
- Carried out on schedule regardless of equipment condition

- so some maintenance work may be redundant and waste resources
- Interventions can inadvertently result in damage to seals, threads, insulation, and so forth

Despite drawbacks, PM remains the core of most maintenance programs and is generally accepted to be of benefit.

11.1.2 Reliability centered maintenance

Reliability centered maintenance provides *appropriate* and *just-in-time* maintenance to prevent forced outages and avoid unnecessary maintenance.

Reliability centered maintenance can be more time- and cost-efficient than preventive maintenance and is an attractive option if funds are diminishing, skilled maintenance staff is scarce, or there is pressure to stay online due to electric utility deregulation.

Features of reliability centered maintenance include the following:

- Implementation is labor-intensive and time-consuming
- Effectiveness may require additional monitoring of parameters, such as temperature and vibration, which may require new monitoring equipment, incurring more preventive maintenance or more staffing for monitoring and inspections
- May defer maintenance and result in a "run-to-failure" for some equipment
- May require trial-and-error revisions to maintenance schedule depending on equipment condition

In general, reliability centered maintenance should achieve a more manageable maintenance workload focused on priority equipment. Sensor technology and data-recording technology now evaluate equipment condition and help predict potential failure or end-of-life for plant components while reducing staff time and costs.

Reliability centered maintenance should never be adopted as a long-term cost-cutting measure aimed at eliminating preventive maintenance.

11.1.3 Condition-based maintenance

Condition-based maintenance, as the name implies, provides appropriate and just-in-time maintenance to prevent forced outages and eliminate redundant maintenance by responding to equipment condition. It concentrates on *sensitive* systems.

Condition-based maintenance includes the following characteristics:

- Monitors and records equipment parameters such as temperatures, pressures, vibrations, leakage current, dissolved gas analysis, etc.
- Tests periodically and/or when problems are suspected, such as double testing, vibration testing, infrared scanning, and so forth
- Continuously analyzes operator-gathered data
- Secures results in knowledgeable maintenance decisions, reduces overall costs, focuses on equipment that requires priority attention

Drawbacks of condition-based maintenance include: some parameters are difficult and expensive to monitor; requires experienced staff for knowledgeable and consistent analysis; monitoring equipment and systems add a layer of required maintenance. Can result in a "run-to-failure" and requires trial-and-error revisions to maintenance schedule. Thus, condition-based maintenance programs are unsuitable as a sole maintenance regimen to run a project.

11.1.4 Combination of condition-based and preventive maintenance

The most practical approach is perhaps a combination of condition-based, reliability-centered and preventive maintenance. Monitoring, testing, and using historical data and preventive schedules may provide the best information about required equipment maintenance. An important component is maintaining accurate records of *as-found* equipment condition when it is torn down for maintenance, which reveals what was necessary and based on this experience and monitoring, maintenance schedules can be lengthened or shortened.

11.2 Performance monitoring evaluation/optimization

In most countries regulatory authorities require project certification in line with ISO 9001 through 9004 (Quality Assurance System) and with ISO 14001 (Environmental Management System).

The project may have to obtain a water diversion and storage permit from regulatory bodies (government); often, project discharges and water levels must be recorded daily or hourly.

On most large hydroelectric projects, a hydrometric network must be established and maintained in the watershed to monitor and acquire climatological and hydrological data.

A deterministic and a statistical runoff model must be established and maintained for inflow forecasting and updated daily, weekly, monthly, and quarterly.

Special attention is required to monitor and maintain storage reservoir shore stability due to expected water-level fluctuations. Siltation of reservoirs must be monitored as well.

Reservoir operating rules should be established and periodically updated. Matrices will be established and refined for time, water level, and likely inflow versus available release.

Equipment availability and reliability will be recorded in Event and Incident Reports to detect equipment weaknesses.

Longer shutdowns will be exceptional occurrences. In general, forced outages will diminish with operating experience and be avoided through preventive maintenance.

Each hydropower plant is a one-off design that is site-specific therefore little standardization is possible in the conceptual and detailed design of plant equipment. As a result, during initial years of operation, hydropower plants typically experience a higher number of forced outages until a satisfactory learning curve and operational experience are attained and the number of incidents requiring corrective and emergency maintenance declines, in part due to preventive maintenance.

11.3 Equipment availability

The availability of electro-mechanical and hydro-mechanical equipment for power generation depends on the quality of the equipment, the qualifications of installers and commissioning contractors and the experience of the plant operator. Typically, required equipment availability is specified in the Power Purchase Agreement between the plant owner/operator and the utility

Table 11-2: Staff composition

Staff	Position	Duties/Activities	Remarks
1	Plant manager	Provide overall management, long-term planning, interface with utilities and state authorities, etc.	
1	Deputy plant manager	Same as above	
14	Operators and shift engineers on duty/ control room	Monitor operation and perform immediate intervention in manual mode in case of problems in the control system or in the remote communications	3-shifts, 7 days/ wk, control room always staffed by 2
2	Mechanical engineer	Check, control and monitor equipment condition; plan and supervise maintenance work; plan required adaptations to auxiliary mechanical equipment; plan and supervise spare parts procurement, etc.	Also on standby for emergency duty
3	Electrical engineers	Check, control and monitor equipment condition; plan and supervise maintenance work; plan required adaptations to the auxiliary electrical equipment; plan and supervise spare parts procurement; etc.	Also on standby for emergency duty
1	Civil engineer	Check, control and monitor condition of civil works; plan and supervise maintenance work; plan required adaptations to civil works; etc.	
3	Skilled mechanic	Perform regular maintenance work, immediate small repairs and rectification	
4	Skilled electrician	Perform regular maintenance work, immediate small repairs and rectification	
8	General worker	Provide support during maintenance and repairs; clean/maintain surroundings, etc.	
3		Perform secretarial, accounting, and human resources services	
40	**Total**		

Source: FICHTNER

buying the power. On average the hydropower plant is available for operation about 95 percent in the first year of operation; the 5.0 percent non-availability (18 days per year) accounts for the following:

- 11 days scheduled maintenance and checks
- 7 days forced outages due to equipment breakdown or malfunction

Typically plant availability improves to 97 or 98 percent after three years of operation, accounting for the following:

- 4 to 6 days scheduled maintenance and checks
- 3 to 5 days forced outages due to equipment breakdown or malfunction

Depending on water quality, operational hours, type of operation (peaking with frequent starts/stops, or base load), a major overhaul of the generating units is required about every 7–12 years, and requires 4-6 weeks for medium and large units (>20 MW), and 1-3 weeks for small hydro (<5 MW).

11.4 O&M staffing and cost

11.4.1 O&M staff

The number of permanent employees required to run and maintain an HPP scheme can vary widely, depending on the following:

- Project size and complexity
- Country of installation
- Local rules and regulations on working hours, shift work, and division of work among specialists (e.g., labor union restrictions), among others
- Staff education, experience and skill level
- Mode of operation imposed by the PPA
- Management decision on whether O&M work will be handled by plant staff or outsourced

Table 11-2 shows typical staff composition required to operate and maintain a 300 MW high-head hydropower project in a middle-income country, with two generating units, dam, storage reservoir, tunnels/ penstocks and interconnecting switchyard to the transmission line.

A project of the same size in a developing country with high unemployment might be staffed with three to ten times the number of employees despite modern technologies, remote control and monitoring. The hydro project is often the only source of employment for local people so staffing might include several deputy managers, facility cleaners, unskilled laborers, administrative staff, tea servers, gardeners, drivers and security personnel.

In industrialized countries with experienced utilities that own many projects (such as Électricité de France SA, US Bureau of Reclamation, or Bayerische Wasserkraftwerke AG), 300 MW plants are often operated in remote mode—a few operators in a central control facility operate and monitor multiple plants for which maintenance work and periodic checks are carried out by "flying teams" that travel to each facility for scheduled maintenance or for immediate trouble-shooting.

11.4.2 Maintenance costs

E&M equipment and civil works are the two main components of O&M, for which costs are in the following range.[6]

E&M: The recommended annual budget for electro-mechanical equipment maintenance is 2.0-2.5 percent of initial investment costs, typically in the following two tranches:

6. Please refer also to Section 13.2.4 to see OPEX benchmarks.

- About 40 percent for ongoing plant maintenance, spare parts, consumables and services outsourced to specialized companies
- About 60 percent for a reserve fund to finance major rehabilitation works that are required every 7-12 years, and unforeseen incidents

Civil works: The budget for civil works maintenance is about 0.4-0.6 percent of their initial investment cost; it covers underground works, reservoirs, access roads, fencing, administration buildings, and so forth.

11.4.3 Spare parts stock

The value of spares in stock for electromechanical, electrical and hydro-mechanical equipment is about 2.5-3.0 percent of the free on board (FOB) equipment price (according to a statistical evaluation of average hydro projects).

11.4.4 O&M contracts

Typically, large utilities have their own operation and maintenance division. Smaller hydropower producers often outsource the work to specialized O&M companies or to the equipment suppliers.

Contracts normally cover *all* aspects of maintaining the entire power station including facilities, structures, buildings and offices; mechanical and electrical systems and controls; drainage systems and water treatment facilities; and power station roads and security fencing.

The contract objective is to keep the power generating system in good working order, to prevent premature deterioration and degradation, and to correct any equipment damage, deterioration or malfunction. The O&M contractor must operate the plant so that it supplies power to the grid system as specified in the owner's obligations to the grid operator under the power purchase agreement (PPA), which also defines legal responsibilities to be passed to the O&M contractor, including penalties for non-performance.

11.5 Typical operation and maintenance procedures

11.5.1 General

The O&M procedures must be well conceived and comply with ISO 9001- 9004 requirements. The following documents cover O&M organization and implementation and are essential to manage and record O&M works:

Maintenance:

- Preventive Maintenance Work Order Implementation
- Corrective Maintenance Work Order System
- Predictive Maintenance and Work Order
- Calibration of Measuring and Test Equipment
- Maintenance On-guard Provision

Operation:

- Customer Requirement Determination
- Handling of Daily Notice of Generation Schedule and Dispatch
- Order
- Operations Shift Schedule Preparations
- Shift Turnover
- Standard Operating Procedure
- Monitoring and Recording of Operating Parameters
- Customer Communication
- Safety Clearance and Tagging.

11.6 Typical procedures

11.6.1 General

The best O&M procedures for hydro projects aim to minimize individual generating unit downtime and supply a level of operational reliability such that grid demands are met with available generation.

Each occurrence of equipment failure should trigger an inquiry into why and how it occurred and how to avoid future recurrence.

When a part or piece of equipment must be replaced, due to breakdown or the end of its useful lifespan, it should be replaced with an improved version of the latest technology whenever available.

Operating conditions should continuously be monitored and recorded because records are critical tools to diagnose the causes of equipment faults, failures, and replacements; and to determine residual lifespan.

Equipment manufacturers recommend maximum/minimum parameters for their equipment, but an operator's records, experiences, and history should also be used to set actual limiting values for equipment parameters.

The O&M maintenance schedules shall be specified and periodically up-dated using recommendations from O&M history and records.

The number of planned starts/stops of each unit shall be minimized to increase the lifespan.

Procurement of equipment spares should be planned based on actual rate of consumption.

11.6.2 Maintenance practice

Some typical practices and activities at hydropower stations for main plant maintenance are listed below.

11.6.2.1 Water intake, power water system and associated equipment

Water storage (reservoir) and the water conductor system—intake, headrace tunnel, surge shaft, emergency valves and pressure shafts, penstock, and main inlet valves—comprise the vital organs of a hydropower plant.

As a result, conduit isolation equipment, i.e., intake gates, butterfly valves, excess flow devices, surge equipment, should be tested regularly.

Furthermore, dams must be inspected regularly and maintenance work, such as repairing eroded areas must be carried out. Larger dams provide a dam-monitoring system that shows drainage flows, and dam and settlement inclination; this system must be maintained and functioning.

Periodic physical inspection of the inside and outside of the water conductor system should take note of condition, silt deposition, and conduit system rusting/erosion to monitor any signs of aging, or stresses due to water hammer, and so forth. Inspection records should note *all details*—normal and abnormal—so these can be compared with installation data. Abnormalities should be further investigated and rectified. Painting should be renewed regularly inside and outside (wherever possible) to protect the conduit system. Deteriorated valve seals should be replaced with new seals of the latest materials to prolong the lifespan of the equipment. Hydraulic system oil purification and frequent testing should be carried out according to manufacturers recommendations.

11.6.2.2 Turbine and its auxiliaries

Cavitations and/or erosion may lead to turbine wheel damage, which undermines performance and efficiency.

- Conduct regular inspections of turbine runners and maintain records. As necessary, carry out in-situ welding repairs on turbine runners to fill cavitations or to repair cracks on the runner blades.

A system for monitoring silt content (quantity and size in PPM) may have to be installed on power stations operating with heavily silted water to assess silt erosion on turbine components and to plan timely repairs or part replacement reducing units/ station down time.

Best efficiency microprocessor-based digital PID speed governors provide rapid response.

- Carry out periodic maintenance of speed governors and all associated mechanical, electrical, and electronic components.
- Calibrate and test transducers, meters and so forth periodically

11.6.2.3 Generator and its auxiliaries

The main generator parts include the stator and rotor winding, bearings and excitation system.

- Record insulation resistance (IR) values of stator windings at regular intervals to assess the condition of stator winding insulation.
- Conduct regular impedance tests (voltage drop test across each pole) to assess rotor-winding condition.
- Maintain cooling system to limit rise in stator winding temperatures to extend life of stator winding.
- Inspect stator winding to verify its firmness in stator core slots, because loose stator core, inter lamination, or core insulation directly affect winding heating due to eddy-current loss.
- Carry out recommended maintenance as per schedule, maintain records and take any necessary corrective actions.

Other precision and critical generator components include the guide and thrust bearings. The thrust bearing is the main bearing holding complete thrust of the rotating mass of turbine and generator unit.

The following works also need to be carried out periodically:

- Check foundations and tighten bolts
- Check vibrations and use history of recorded readings as guidelines for realignment; check for any looseness, unbalanced electrical components, increase in bearing gaps, coupling misalignment, uneven stator-rotor air gap, and so forth
- Clean or replace generator air coolers and bearing oil coolers to improve generator performance
- Conduct primary and secondary testing of protection system for correct operation
- Inspect current transformers, potential transformers and bus bars for overheating, or temperature rise
- Inspect circuits for protection and control circuits; conduct mock trials of fire-fighting system and evacuation system

11.6.2.4 Transformer and switchyard

- Continuously monitor oil and winding temperature
- Periodically filter oil
- Conduct various oil tests and dissolved gas analysis.
- Check tandelta and insulation resistance, etc. as per schedule
- Clean and replace oil cooler
- Test protection system for correct functioning
- Conduct mock trials: check, maintain and inspect firefighting system, CO2 and mulsifire
- Test breaker operation time
- Operate and test isolator opening and closing
- Check control circuit and breaker operating system function
- Periodically clean transformer bushings and insulator strings

Switchyards are to be kept clean and tidy; area surrounding the yard is to be kept free from growth of scrubs and bushes to diminish risk of bush fire damage to equipment.

11.6.2.5 Emergency diesel generator set

- Regular maintenance of the emergency set
- Check control and protection system
- Run DG set at regular intervals

11.6.2.6 Other powerhouse equipment

- Periodically maintain unit auxiliary, station auxiliary and station service transformer
- Check station batteries and battery chargers
- Regularly inspect cable ducts for proper ventilation/heat dissipation.

This chapter illustrates typical E&S concerns by comparing two common project types: traditional large hydroelectric reservoir/storage dams (large hydro) and run-of-river schemes (small hydro).

12 Environmental and Social Impact Mitigation

This chapter provides an overview of key environmental and social (E&S) impacts and mitigation measures for HPP developments. The chapter explores in greater details the relation with Equator Principles and IFC Performance Standards, briefly explained in chapter 8.2.3.

Regardless of project size, the project owner is ultimately responsible for ensuring that all environmental and social impacts are taken into account following best practices, domestic regulatory requirements, and financing institution expectations.[7]

In general, local E&S impacts of HPP projects vary depending on project size, type/technology, site and other local conditions. Since new energy developments are often catalysts for broader socio-economic development, new HPP investments must be wisely selected, sited and managed to maximize overall benefits and mitigate any negative consequences.

As discussed, each HPP development is unique and HPPs vary widely depending on a range of factors, therefore each project presents an equally complex range of E&S risks. However, this chapter illustrates typical E&S concerns by comparing two common project types: traditional large hydroelectric reservoir/storage dams (large hydro) and run-of-river schemes (small hydro).

7. Total impacts also include what is referred to as *cumulative impacts* from multiple projects. From E&S perspective, one large dam of 1,500 MW situated in a remote area on one river basin may or may not have fewer negative impacts than the combined/cumulative impacts of 100 or 200 small-scale projects located on many rivers. See IFC's Good Practice Handbook for guidelines on cumulative impact assessment; full reference listed in Section 16.

12.1 Environmental impacts and mitigation for large HPP, especially dams

Of all HPP project types, large hydroelectric dams attract most attention and controversy. Advocates for large dams point out that such projects are frequently the least-cost option among potential electric power options, particularly for larger urban areas. Also, they point out that other power generating technologies carry negative E&S impacts, and that large dams are a renewable energy source. Critics tend to cite biodiversity destruction, human settlement displacement, and inappropriate site selection from a participatory and/or E&S point of view.

At the broadest level, site selection is the single largest determinant of the scale of E&S risks linked to any type of dam (refer to section 6.5.7 for some of the typical issues to consider during the site selection process). If the site is wisely selected to avoid or minimize negative E&S impacts, well-designed mitigation measures will balance the cost/benefit equation (see Table 12 1). If the site is unsuitable, no mitigation measures can redress cost/benefit imbalance.

In general, large dam projects with a smaller reservoir surface area (relative to power generation) tend to be most desirable from an E&S standpoint, in part because they minimize natural habitat losses and resettlement requirements. Most environmentally benign hydroelectric dam sites are on upper tributaries; the most problematic sites are on large main stems of rivers [World Bank 2003]. However, the specific context needs to be assessed as dams sited on upper tributaries usually involve longer diversion schemes and therefore have the potential to create longer dewatered sections.

Table 12-1: Large Dams: some of the typical negative environmental and social impacts

Impacts	Mitigation options
Flooding of Natural Habitats	
Some reservoirs permanently flood extensive natural habitats causing local or even global extinctions of animal and plant species. Very large hydroelectric reservoirs in the tropics are especially likely to cause species extinctions, although such losses are rarely documented due to lack of scientific data. Particularly hard-hit are riverine forests and other riparian ecosystems, which naturally occur only along rivers and streams. From the perspective of biodiversity conservation, terrestrial natural habitats lost to flooding are usually much more valuable than the aquatic habitats created by the reservoir. An exception to this can be the shallow reservoirs in dry zones that can provide a permanent oasis, sometimes important for migratory waterfowl and other terrestrial and aquatic fauna.	**Compensatory protected areas** can be established and managed under the project to offset the loss of natural habitats due to reservoir flooding or other project components, such as borrow pits. If an existing area is protected in legislation but not in fact, a useful project option is to strengthen on-the-ground protection and management. Ideally, the area protected under the project should be of comparable or greater size and ecological quality to the natural area lost to the project. Under the IFC PS 6, projects should not be sited where they would cause the significant conversion or degradation of natural and critical natural habitats unless certain specific conditions are met.
Loss of Terrestrial Wildlife	
During reservoir filling terrestrial wildlife can be lost to drowning as a consequence of flooding terrestrial natural habitats, although this is often treated as a separate impact	Wildlife rescue efforts rarely succeed in restoring wild populations, although they have a value in public perception. Captured and relocated animals typically starve, are killed by competitors or predators, or fail to reproduce due to the limited carrying capacity of new habitats. Wildlife rescue is justified on conservation grounds if (a) the rescued species are globally threatened with extinction and (b) the new habitat is ecologically suitable and protected. Otherwise, wildlife conservation efforts would be better served by investing in compensatory protected areas. To effectively minimize wildlife mortality in hydroelectric projects dam sites should be selected to minimize the area of wildlife habitat that is flooded.
Involuntary Displacement	
Involuntary displacement of people is considered the most adverse social impact of hydroelectric projects. Involuntary displacement can also have important environmental implications, such as when natural habitats are converted to accommodate resettled rural populations.	For physical displacement, the main mitigation measure is to resettle displaced populations and provide new housing, replacement lands, and other material assistance. Successful resettlement requires consultation and participatory decision making on the part of the resettled and host populations (mandatory for World Bank Group-supported resettlement). Effective resettlement of vulnerable ethnic minorities is particularly challenging. The IFC PS 5 specifies that, among other requirements, to consider feasible alternative project designs to avoid or minimize physical and/or economic displacement, while balancing environmental, social and financial costs and benefits, paying particular attention to impacts on the poor and vulnerable. In cases of economic loss of livelihoods (based on fisheries, agricultural or grazing lands, river-edge clay for brick and tile production, or other resources) without physical displacement, mitigation measures should include replacement resources, job training, or other income restoration assistance.
Deterioration of Water Quality	
Damming rivers can reduce water quality due to lower oxygenation and dilution of pollutants by reservoirs that are relatively stagnant compared to fast-flowing rivers. Also, flooding of biomass (especially forests) creates underwater decay; and due to reservoir stratification water quality can decline because deeper lake waters lack oxygen.	Water pollution control measures (such as sewage treatment plants or enforcement of industrial regulations) may be needed to improve reservoir water quality. Selective forest clearing within the impoundment area should be completed before reservoir filling to mitigate poor water quality resulting from decay of flooded biomass.
Downriver Hydrological Changes	
Major downriver hydrological changes can destroy riparian ecosystems dependent on periodic natural flooding, exacerbate water pollution during low-flow periods, and increase saltwater intrusion near river mouths. Reduced sediment and nutrient loads downriver of dams can increase so-called river-edge and coastal erosion, and damage the biological and economic productivity of rivers and estuaries. Induced desiccation of rivers below dams (when the water is diverted to another portion of the river, or to a different river) kills fish and other fauna and flora dependent on the river; it can also damage agriculture and human water supplies.	Managed water releases can mitigate these adverse impacts. Objectives to consider in optimizing water releases from the turbines and spillways include: (a) adequate downriver water supply for riparian ecosystems, (b) reservoir and downriver fish survival, (c) reservoir and downriver water quality, (d) aquatic weed and disease vector control, (e) irrigation and other human uses of water, (f) downriver flood protection, (g) recreation (e.g., whitewater boating), and (h) power generation. From an ecological standpoint, the ideal water-release pattern would closely mimic the natural flooding regime, although this may not be feasible for densely settled floodplains where flood protection is a priority. Dams that generate base load electricity are typically more capable of replicating near-natural downriver flows than those that produce peaking power (where daily water releases may fluctuate sharply, often to the detriment of aquatic organisms that are adapted to less frequent flow changes). Environmental management plans for hydroelectric projects should specify environmental water releases, including for private sector owned or operated dams.
Water-related Diseases	
Some infectious diseases can spread around hydroelectric reservoirs, particularly in warm climates and densely populated areas. Some diseases (such as malaria and schistosomiasis) are borne by water-dependent disease vectors (mosquitoes and aquatic snails); others (such as dysentery, cholera, and hepatitis A) are spread by contaminated water, which frequently becomes worse in stagnant reservoirs than it was in fast-flowing rivers.	Public health strategies should include preventive measures such as investing in public awareness campaigns and window screens, monitoring disease vectors and outbreaks, controlling disease vectors, and treating cases. Controlling floating aquatic weeds (see below) near populated areas can reduce the risks of mosquito-borne disease.

(continued)

Table 12-1: Large Dams: some of the typical negative environmental and social impacts (continued)

Impacts	Mitigation options
Fish and Other Aquatic Life	
Hydroelectric projects often have major effects on fish and other aquatic life. Reservoirs positively affect certain fish species (and fisheries) by increasing the area of available aquatic habitat. However, the net impacts are often negative because (a) the dam blocks upriver fish migrations, while downriver passage through turbines or over spillways is often unsuccessful; (b) many river-adapted fish and other aquatic species cannot survive in artificial lakes; (c) changes in downriver flow patterns adversely affect many species, and (d) water quality deterioration in or below reservoirs (usually low oxygen levels; sometimes gas super-saturation) kills fish and damages aquatic habitats. Freshwater mollusks, crustaceans, and other benthic organisms are even more sensitive to these changes than most fish species, due to their limited mobility	Managed water releases may be needed for the survival of certain fish species in and below the reservoir. Fish passage facilities (fish ladders, elevators, or trap-and-truck operations) aim to help migratory fish move upriver past a dam but are usually of limited effectiveness due to the difficulty of ensuring safe downriver passage for many adult fish and fry. Fish hatcheries can be useful for maintaining populations of native species that can survive but not successfully reproduce within the reservoir. Also fish hatcheries are often used for stocking the reservoir with economically desired species; introducing non-native fish is not ecologically desirable because of the often catastrophic effects on native species. Often, fishing regulations are essential to maintain viable populations of commercially valuable species, especially in the waters immediately below a dam where migratory fish species concentrate in high numbers and are unnaturally easy to catch.
Floating Aquatic Vegetation	
Floating aquatic vegetation can rapidly proliferate in eutrophic reservoirs, causing problems such as (a) degraded habitat for most species of fish and other aquatic life, (b) improved breeding grounds for mosquitoes and other nuisance species and disease vectors, (c) impeded navigation and swimming, (d) clogging of electro-mechanical equipment at dams, and (e) increased water loss from some reservoirs.	Undertaking pollution control and pre-impoundment selective forest clearing reduces aquatic weed growth in reservoirs. Physical removal or containment of floating aquatic weeds is effective but imposes a high and recurrent expense for large reservoirs. Where compatible with other objectives (power generation, fish survival, etc.), occasional drawdown of reservoir water levels may be used to kill aquatic weeds. Using chemicals to poison weeds or related insect pests is best avoided due to the environmental and human health risks it poses.
Loss of Cultural Property	
Cultural property, including archaeological, historical, paleontological, and religious sites and objects, can be inundated by reservoirs or destroyed by associated quarries, borrow pits, roads, or other works.	Structures and objects of cultural interest should be salvaged wherever feasible through scientific inventory, careful physical relocation, documentation and preservation in museums or other facilities. However, unique or sacred sites with religious or ceremonial significance to indigenous or local people usually cannot be replaced.
Reservoir Sedimentation	
Over time, reservoir sedimentation reduces live storage and power generation to a degree that could also lower the projects' long-term prospects for renewable energy over the long term.	Effectively implemented watershed management can minimize sedimentation and extend the reservoir's useful physical life by controlling road construction, mining, agriculture, and other land use in the upper catchment area. For this reason, protected areas are sometimes established in upper catchments to reduce sediment flows into reservoirs, as with the Fortuna Dam in Panama and the proposed Rio Amoya (Colombia) and Nam Theun II (Laos) projects. Other sediment management techniques for hydroelectric reservoirs include installing upstream check structures, protecting dam outlets, flushing the reservoir, removing sediment mechanically, and increasing dam height, if physically and economically feasible.
Greenhouse Gases	
Greenhouse gases (carbon dioxide and methane) are released into the atmosphere from reservoirs that flood forests and other biomass, either slowly as flooded organic matter decomposes, or rapidly if the forest is cut and burned before reservoir filling. Greenhouse gases are widely considered to be the main cause of human-induced global climate change. Many hydroelectric reservoirs flood relatively little forest or other biomass. Moreover, most such hydro projects generate sufficient electricity to more than offset the greenhouse gases that would otherwise have been produced by burning fossil fuels (natural gas, fuel oil, or coal) in power plants. However, some projects that flood extensive forest areas, such as the Balbina Dam in Amazonian Brazil, appear to emit greenhouse gases in greater amounts than would be produced by burning natural gas for many years of comparable electricity generation.	Greenhouse gas releases from reservoirs can be reduced with a thorough salvage of commercial timber and fuel wood. However, this rarely happens due to (a) high cost of extraction and transportation, (b) marketing constraints, or (c) political and economic pressures to avoid delays in filling the reservoir. The best way to minimize greenhouse gas releases from reservoirs is to select dam sites that minimize flooding of land in general and forests in particular.

(continued)

Table 12-1: Large Dams: some of the typical negative environmental and social impacts (continued)

Impacts	Mitigation options
Impacts of Associated Civil Works	
Access Roads	
New access roads to hydroelectric dams can induce major land use changes—particularly deforestation—with resulting loss of biodiversity, accelerated erosion, and other environmental problems. In some projects (such as Arun II in Nepal), the environmental impacts of access roads can greatly exceed those of the reservoir.	New access roads should be sited in corridors that incur the least environmental and social damage. Forests and other environmentally sensitive areas along the selected road corridor should receive legal and physical protection. Road engineering should ensure drainage to protect waterways and minimize erosion. Environmental rules for contractors (including penalties for noncompliance) should cover construction camp siting, gravel extraction, waste disposal, water pollution, worker behavior (e.g., no hunting), and other good practices for construction.
Power Transmission Lines	
Power transmission line right-of-ways can reduce and fragment forests; indirectly, they can increase deforestation by improving physical access. Power lines are responsible for deaths of large birds; power lines are considered an aesthetic blight.	Power lines should be sited to minimize concerns and built using good environmental practices. Where concentrations of vulnerable bird species exist, the top (grounding) wire should be made more visible with plastic devices. Electrocution (mainly of large birds of prey) can be avoided through bird-friendly tower design and proper spacing of conducting wires. (Refer to WBG EHS Guidelines for Electric Power Transmission and Distribution.)
Quarries and Borrow Pits	
Quarries and borrow pits are used to provide material for construction of the dam and complementary works. They can considerably increase the area of natural habitats or agricultural lands that are lost to a hydroelectric project.	To the greatest extent feasible, quarries and borrow pits should be sited within the future inundation zone. Where this is not feasible, pits should be rehabilitated after use, ideally for conservation purposes such as wetland habitats. (Refer to WBG EHS Guidelines for Construction Materials Extraction.)
Impacts Induced Development	
Follow-on Development Projects	
Hydroelectric dams often make possible new development projects with major environmental impacts, including irrigation, urban expansion, and industrial facilities (due to new water supplies).	Assessment of the cumulative impacts is needed. Associated development projects should be planned to minimize adverse environmental and social impacts. Environmental impact assessment studies should be carried out in the early stages of project planning and the resulting environmental mitigation plans should be fully implemented.
Additional Dams	
The construction of the first dam on a river can make subsequent construction of additional dams more economical because flow regulation by the upriver dam can enhance power generation at the downriver dam(s).	Ideally, the environmental and social impact assessment study for the first dam on any river should include a cumulative impact assessment for any known proposed additional dams on the same river system. Mitigation measures for cumulative (rather than dam-specific) impacts should be completed or well underway before construction of the second dam.

Source: Adapted from World Bank 2003

12.2 Key E&S characteristics of smaller HPP, especially run-of-river

Most smaller hydroelectric projects have smaller environmental impacts than a large dam because small HPPs rely on smaller flows diverted from a river, rather than blocking the entire river flow. Indeed, smaller hydro generating facilities are appealing and an increasingly popular choice for rural and remote regions with nearby rivers because other energy sources are less viable. In addition, construction periods are generally shorter for individual small HPP (SHPP) developments and permitting approval tends to be simpler, which reduces costs and increases the suitability for local energy needs [UNEP 2007].

Below is a summary of lessons learned from small HPP projects such as many run-of-river schemes. The summary builds on World Bank 2009, key E&S-relevant features, advantages, and concerns.

Features

The following are SHPP features:

- Installed capacity is not an indicator of potential project impacts
- Small-scale and run-of-river does not mean zero or even low-impact
- Projects can be important and desirable locally, but still raise controversy that must be carefully managed throughout the entire development process

Key advantages of smaller hydropower include the following:

1. Most SHPPs can provide electricity with low E&S impacts. They represent so-called *green* or *low-impact* energy alternatives because they offer:
   - Lower or more acceptable environmental and social impacts than alternative fossil-fuel burning projects
   - Environmental and social benefits balance environmental and social costs
   - Scale of works increases potential sustainability by reducing or eliminating risks normally associated with large-scale hydro
2. Typically, SHPPs employ run-of-river design and do not require reservoir storage capacity
3. Do not involve large or complex resettlement or land acquisition
4. Projects can be brought on-line more rapidly and expect to benefit from a streamlined review and processing

requirements, assuming government capacity to manage a streamlined process (not always the case in emerging economies).

Key concerns include the following:

1. Risks are inherent in any size of project and must be properly managed to avoid threatening project sustainability or incurring reputational or other risks. In general, environmental and social concerns for SHPPs may occur in the following aspects of HPP development:
   - At and above dams or barriers
   - Below dam–especially at diverted /dewatered river reaches
   - Associated infrastructure–access roads, borrow pits and transmission lines
   - Operational impacts affecting river flow timing/volumes
   - Aggregate impacts of multiple dams, other projects in the same watershed
   - Land acquisition or physical resettlement (less likely than for large hydro)
   - From issues linked to land and resource tenure including access to water resources
   - Expectations for associated community development, livelihood support and/or benefits sharing

Lessons learned include the following:

In general, emerging economy experience with SHPPs demonstrates:

- Need to consider all impacts, including construction-related impacts of ancillary works such as roads.
- Stakeholder involvement and improved two-way communications are crucial to success and should be ongoing from inception to commissioning.
- Support capacity building of government agencies, beyond project counterparts. For example, local government units must often carry out monitoring and compliance tasks but may lack capacity to do so.
- Coordinate inter-agency dialogue among project agency stakeholders.
- Reduce project E&S liabilities by developing clear agreements and monitorable outcomes, detailed annual work plans, and budget resources to accomplish them.
- Clarify process requirements regarding legal framework, regulations, institutional roles and responsibilities.
- Desire for efficient review process. Project developers desire more rapid and efficient licensing procedures from authorities.
- Project proponents, often small IPP, may lack sufficient experience or resources to successfully implement programs.
- Construction and operational delays may threaten a company's financial viability and ability to meet E&S commitments.
- Even small projects can face adverse local attitudes regarding transparency, communications, and community development support.
- Managing community expectations even for small hydro can be difficult and challenging.

12.3 Equator Principles

As briefly presented in chapter 8.2.3, the Equator Principles (EP) are a financial industry agreement to determine, assess and manage social and environmental risks in project finance and project-related corporate loans. In adopting the Equator Principles a financial institution commits to provide loans only to those projects whose sponsors can demonstrate ability and willingness to adhere to comprehensive processes for environmentally and socially responsible management practices. The EP signatories include global and developing country banks that provide project finance to companies in emerging markets.

The Equator Principles emphasize and promote convergence around common environmental and social standards in project finance. Multilateral development banks, including the European Bank for Reconstruction and Development (EBRD), and export credit agencies through the Organization for Economic Cooperation and Development (OECD) Common Approaches, are increasingly drawing on the same standards as the Equator Principles when pursuing sustainability in their operations. The EPs are now considered a benchmark of project, energy and infrastructure finance.

The third EP iteration was released June 2013 (EP III). See Box 12-1.

The 2012 revision of the IFC Performance Standards on Environmental and Social Sustainability are the technical reference of the EP framework. For bankers and those seeking capital, the EP and, thus, the IFC Performance Standards provide key references for minimum required environmental and social risk management practices.

The EPs were never intended to apply retroactively, but signatory institutions also apply the principles to upgrades and expansions of existing projects where such changes notably alter the nature or degree of existing E&S threats or create significant new E&S risks and impacts.

The EPs are a starting point; they reflect a forward-looking due diligence framework to guide balanced risk decisions but they are high-level principles and not intended to address site-specific local E&S concerns.

Box 12-1: The 2013 EP III Statement of Principles

Principle 1 - Review and categorization
Principle 2 - Environmental and social assessment
Principle 3 - Applicable environmental and social standards
Principle 4 - Environmental and social management system and EP action plan
Principle 5 - Stakeholder engagement
Principle 6 - Grievance mechanism
Principle 7 - Independent review
Principle 8 - Covenants
Principle 9 - Independent monitoring and reporting
Principle 10 - Reporting and transparency

The Equator Principles full text is available at www.equator-principles.com.

Table 12-2: High-level HPP Screening Scorecard
Sample template for profiling HPP developers/owners with view to optimizing E&S features of new investment projects

Success Factor	Yes	No	Partly	Adequacy of available information to rate success factors[a]	Remarks
1. Strong upper management commitment to E&S factors by project developer/owner					
2. Strong demonstrated commitment of the on-site project manager					
3. Demonstrated will to resolve unexpected impacts/issues					
4. Dedicated staff development for all project E&S needs					
5. Proactive communications with local stakeholders throughout project cycle; community involvement from the start					
6. Established community information project website or other systematic communication platform					
7. Adequate ESIA[b] and ESMP[c] with vision toward overall project sustainability					
8. Clear E&S mitigation implementation procedures following ESMP					
9. Clear documented targets and commitments conforming to final ESMP needs					
10. General project monitoring and presence of follow up mechanisms in company					
11. Specific mechanisms for complaints and grievances					

a Sample scale: 1 poor to 5 excellent b Environment & Social Impact Assessment c Environment and Social Management Plan

Source: FICHTNER

EP implications for HPP

Hydropower developers that obtain or expect to obtain finance from EP signatory banks shall adhere to EP and the IFC Performance Standards. Projects receiving finance from these banks would need to demonstrate compliance with EP and the IFC Performance Standards.[8]

Under EP transactions, borrowers commit (make a covenant) to specified actions to manage and mitigate E&S concerns. Borrowers that fail to undertake these actions are considered in breach of the covenant, which allows the financing institution to take corrective action, up to and including cancelling the loan and demanding repayment.

Although smaller SHPP projects may not trigger EP thresholds, the spirit of the Principles should guide the development and operation of the HPP.[9] Moreover, there is no such threshold for the application of the IFC PS.

12.4 E&S screening template adaptable to all HPP project types

Typically during the HPP project-screening phase, financing institution project advisors would provide a preliminary opinion about the potential E&S viability of the proposed investment, regardless of its size or type.

Project advisors take into account their knowledge of the HPP developer/owner, project characteristics, and broader project context when they rate the proposed HPP according to a range of factors considered necessary for an acceptable E&S project profile. Table 12-2 provides a sample scorecard that can be adapted and elaborated for rating projects.

Project advisors are responsible for putting scorecard results into the correct context. In general, results reveal whether the project has good or excellent potential, and whether it has established sufficiently rigorous and efficient management of project-related E&S. However, the screening stage is too early to accurately evaluate success factors. Consequently, advisors must exercise their judgment and offer an opinion about whether the project developer/owner is likely or unlikely to experience major challenges in addressing some project aspects.

The scorecard is a simple tool to help systematize preliminary project assessments but the advisory opinion is provisional. Only a full HPP due diligence can provide a robust E&S review of the proposed project.

12.5 Conclusions

Hydropower can help trigger economic and social development by providing energy and water management services, now and in the future. During lean flows and drought, hydro storage capacity can mitigate freshwater scarcity by providing a secure source for drinking water supply, irrigation, flood control and navigation. Multipurpose hydropower projects provide value beyond the electricity sector as a financing instrument for

8. As of September 2014, 80 financial institutions in 34 countries have officially adopted the EPs, covering over 70 percent of international project finance debt in emerging markets.

9. Thresholds and criteria for EP application are detailed under *Scope* at www.equator-principles.com

reservoirs that help to secure freshwater availability. According to the World Bank, the multiplier effects of large hydropower projects can create an additional **US$0.04 to US$1.00 of indirect benefits for every dollar** of value generated. Furthermore, hydropower can serve in large centralized grids, and small isolated grids; smaller-scale hydropower is a good option for rural electrification [Kumar et al. 2011].

Major international initiatives [10] have reaffirmed the commitment of national governments and international agencies (including the World Bank Group) to more sustainable hydropower development. This commitment recognizes and embraces a newly evolving approach to address environmental and social concerns. Both the Equator Principles and the IFC Performance Standards complement and supplement those broader goals and pay particular attention to sustainable project financing. Sector trade associations such as the International Hydropower Association are working to improve sustainability-oriented protocols for HPP developments.

Hydropower projects have an impact on climate change, and are impacted by climate change, as summarized in Box 12-2.

Many existing HPP technologies are mature and well understood, and ongoing developments can ensure continuous improvement of future HPP developments that will incorporate such innovations as integrated river basin management, resource-efficient tunneling, silt erosion resistant materials, and increasingly fish-friendly turbines [Kumar et al.]. Despite improved technologies, future HPP projects will continue to require a rigorous and cost-effective approach to identify and manage E&S impacts throughout the project cycle, using verifiable means.

Box 12-2: Interactions between hydropower and climate change

IMPACTS FROM HPP ON CLIMATE CHANGE

Hydropower offers significant potential for carbon emissions reductions. Baseline projections of the global supply of hydropower rise from 12.8 EJ in 2009 to 13 EJ in 2020, 15 EJ in 2030 and 18 EJ in 2050 in the median case. Steady growth in the supply of hydropower is therefore projected to occur even in the absence of greenhouse gas (GHG) mitigation.

IMPACTS FROM CLIMATE CHANGE ON HPP

As noted by Kumar et al.'s report for the IPCC (2011), climate change is expected to increase overall average precipitation and runoff, but regional patterns will vary: the impacts on hydropower generation are likely to be small on a global basis, but significant regional changes in river flow volumes and timing may pose challenges for planning. The potential for precipitation patterns to change should be considered in project planning.

10. These initiatives include the 2002 World Summit on Sustainable Development; the 2003 World Water Forum; activities under World Commission on Dams; and UNEP Dams and Development Project.

This section of the guide presents the typical cost structure of hydropower plants, and cost ranges for individual items in HPP construction and operation.

Capital and O&M Costs

13

Assessing the financial viability of a hydropower project requires estimates of capital costs (CAPEX) and operating and maintenance costs (OPEX), plus estimates of the energy yield and associated tariff (see also Section 14.1.2 below). Since this initial assessment helps the developer or investor decide whether to proceed with the project, detailed and precise information on cost structure and cost level for individual plant items provides a better basis for the decision.

This section of the guide presents the typical cost structure of hydropower plants, and cost ranges for individual items in HPP construction and operation. The aim is to establish cost benchmarks for capital and operational expenditures that will enable project evaluation. As has been reiterated throughout this guide, hydro projects are site-specific, therefore cost estimates presented here cannot substitute for pre-feasibility and feasibility studies.

This section will include international cost estimates derived by International Renewable Energy Agency [IRENA 2012] and a benchmarking exercise. Since IRENA does not provide a dataset, estimates derived were verified with data from 19 individual HPPs.

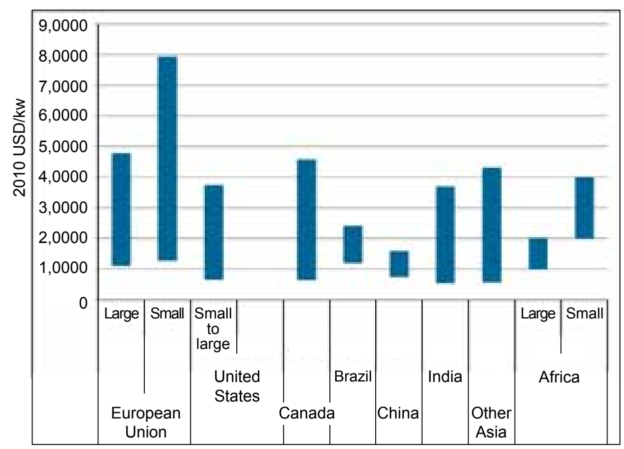
13.1 International cost estimates

IRENA conducted a study designed to provide objective cost data for renewable energy technologies, including hydropower. Cost indicators were derived for investment costs, annual operation, maintenance costs (O&M), and the cost of electricity generated as measured by levelized cost of electricity (LCOE) (see Section 14 for LCOE definition).

Total investment costs for hydropower vary significantly depending on the site, design choices and the cost of local labor and materials. To capture these differences IRENA compiled a dataset derived from countries around the world and including different HPP technologies (run-of-river, storage and pump storage). Study results indicated that total installed costs for large hydropower projects typically range from US$1,000/kW to US$3,500/kW for Greenfield projects; for remote locations without adequate infrastructure or nearby transmission networks, project costs may exceed US$3,500/kW.

Costs for small HPPs are slightly higher because they lack economies of scale. Small hydro projects range from US$1,300/kW to US$8,000/kW. Significant cost differences exist for small and large HPPs across countries, as summarized in Figure 13-1.

Figure 13-1: HPP cost ranges by country

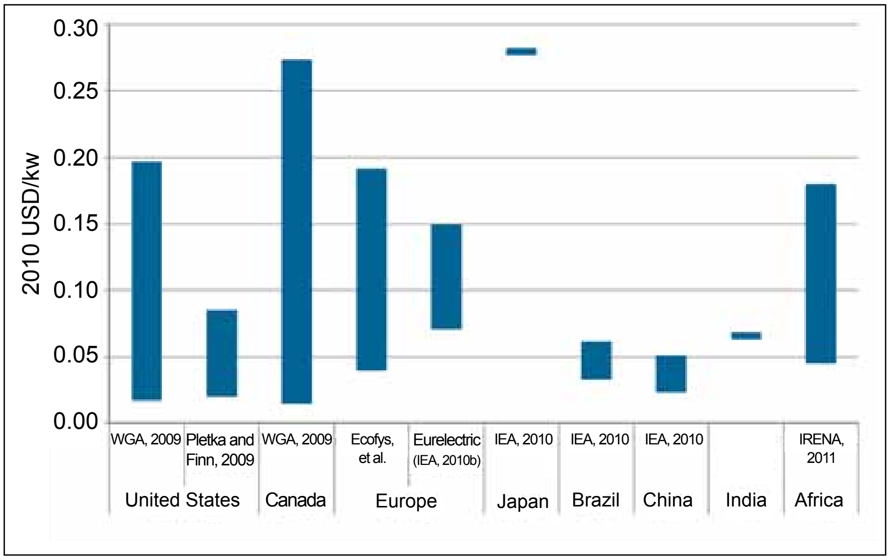


Source: IRENA, 2011

The O&M costs, typically quoted as percentages of investment costs, range from 1.0 percent to about 4.0 percent. The IEA assumes 2.2 percent for large HPP and 2.2 percent to 3.0 percent for small HPP. However, those indicators do not cover major electro-mechanical equipment replacement, which are infrequent due to long design lives. Taking this into consideration, O&M costs average at US$45/kW/year for large HPP and US$52/kW/year for small HPP.

Electricity generation costs range from US$0.02/kWh to US$0.085/kWh; the lowest costs are for additional capacity at existing HPP schemes. Electricity generation costs vary widely across countries because some countries, notably in Europe, have already constructed most of their exploitable HPP projects. Figure 13-2 depicts bands of HPP costs for electricity generation.

Figure 13-2: LCOE by country and region



Source: IRENA, 2011

Table 13-1 summarizes typical investment, O&M and costs of electricity generation as derived by IRENA.

Table 13-1: Summary of HPP costs

	Installed costs (US$/kW)	Operations and maintenance costs (%/year of installed costs)	Capacity factor (%)	Levelized cost of electricity (2010 US$/kWh)
Large hydro	1,050 – 7,650	2 – 2.5	25 to 90	0.02 – 0.19
Small hydro	1,300 – 8,000	1 – 4	20 to 95	0.02 – 0.27
Refurbishment/ upgrade	500 – 1,000	1 – 6		0.01 – 0.05

Source: FICHTNER

13.2 Further analysis of specific CAPEX

Since data from sources such as IRENA are available only on a highly aggregated level, the following analysis investigates CAPEX benchmarks, in particular deriving benchmarks for specific CAPEX components. Also the analysis will show whether CAPEX estimates are within the range band derived by IRENA. Analysis was based on in-house (Fichtner) data from 19 individual HPPs. Data include small, medium and large HPP in Asia, Europe, South America and Africa, from feasibility studies and actual data.

First, CAPEX components (Table 13-2) are appraised and aggregated to a level that allows comparability; next, the four types of benchmarks described below for CAPEX and OPEX are analyzed.

The first benchmark examines the per-unit level to enable comparison among all types and sizes of HPP, and calculate installed capacity costs per kW. Since information sources are derived from different years, all plant prices have been converted to a 2013 price basis.

Second, a benchmark is calculated for each CAPEX component described below by calculating the average across the dataset. As CAPEX components determine total CAPEX, the benchmark for total CAPEX is calculated using CAPEX component benchmarks.

Another benchmark is calculated for O&M costs and expressed on a per-unit level, US$/kW in 2013 prices, to enhance comparability.

Finally, to assess whether high capital and operational expenditures are justified by high energy outputs, a benchmark is calculated for the Levelized Costs of Electricity (LCOE) and expressed in US$/kWh in 2013 prices.

13.2.1 CAPEX components

Capital expenditures (CAPEX) include cost items of all relevant HPP components and for the CAPEX benchmark, seven groups of CAPEX items were defined as follows:

- Project development/engineering/environmental and social costs
- Civil works
- Electro-mechanical equipment
- Grid connection
- Other equipment/construction
- Other non-equipment/non-construction
- Contingencies

The non-equipment/non-construction is a residual group of items that cannot be included in any other groups because they are often related to plant financing. Examples include accommodation camps, dredging equipment, borrow pits, temporary electricity supply, interest during construction, loan costs, taxes, or import charges; these costs vary widely among countries, based on national regimes, and are irrelevant for benchmarking the main costs of a HPP, hence they are not included in this study.

Table 13-2: Main CAPEX groups and sub-items

Main Item	Sub-item
Project development / Engineering / Environmental and social costs	Design documentation
	Engineering
	Supervision
	Administration
	Environmental studies and mitigation costs
	Social studies and mitigation costs
	Resettlement action plan and costs
	Permits and licenses
Civil works	Mobilization/demobilization
	Access roads
	Diversion works
	Intake
	Headrace and waterways
	Forebay
	Surge tank
	Spillway
	Penstock
	Dam
	Powerhouse
	Digging of riverbeds/tailrace
	Fishpass
E&M equipment	Turbine
	Governor
	Valves
	Controller
	Generator
	Hydraulic steel structures
Other equipment / construction	Accommodation camp/bungalows
	Dredging equipment
	Other
Grid connection	Switchyard
	Transmission lines
	Other grid connection
Contingencies	Contingencies for the various sub-items

Source: FICHTNER

Table 13-2 shows a full overview of sub-items and their groupings.

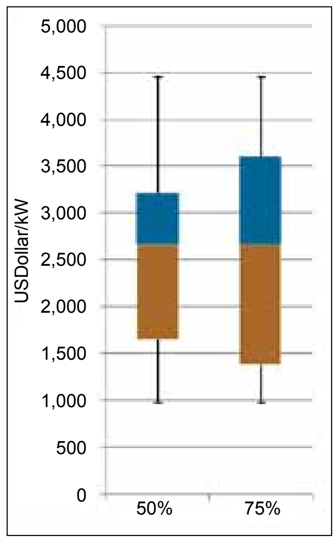
In the following section, total plant costs are analyzed to identify a benchmark for hydropower plant CAPEX. Total plant costs are the sum of costs for project development, engineering, environmental and social costs (hereinafter referred to as *project development*), plus costs for civil works, E&M equipment, other equipment, and construction costs (hereinafter referred to as other) and contingencies. Grid connection costs are analyzed separately; they defy comparability since each plant differs in its proximity to the existing grid, hence the wide range of connection costs.

Table 13-3: Unit costs for each main cost group and at aggregate level (US$/kW)

Main cost group	Min	Median	Average	Max	Coefficient of variation
Project development	42.2	216.8	256.4	744.6	0.78
Civil works	408.4	1,202.6	1,396.8	2822.1	0.47
E&M equipment	174.6	774.9	821.0	1363.5	0.49
Other	1.3	30.3	44.2	136.9	0.55
Contingencies	64.0	204.4	212.7	500.4	0.58
Total plant unit costs	981.1	2,658.6	2,531.9	4,459.2	0.40

Source: FICHTNER

Figure 13-3: Total plant cost



Source: FICHTNER

13.2.2 CAPEX benchmarks

13.2.2.1 Benchmarks of specific unit costs

Total plant costs and individual costs for each of the main CAPEX components differ significantly since each HPP is unique. Table 13-3 presents specific HPP costs expressed US$/kW installed capacity.

Average costs for appraised power plants are about US$2,500/kW, which conforms to IRENA results. Table 13-3 and Figure 13-3 show a wide range of total plant costs, varying by a factor of close to 5. However, the mean 50 percent of plants are closer in range, about US$1,600/kW–US$3,200/kW, which

Box 13-1: Case study SHPP in Western Balkan Region

For the Balkan Renewable Energy Program (BREP) developed and implemented by IFC, Fichtner prepared a budgeting manual, including a comprehensive CAPEX benchmark exercise covering more than 30 small HPPs evaluated by Fichtner during 2009-2013, as part of comprehensive training materials for SHPP Project Finance. The analysis shows that specific costs of SHPP in the region are typically US$1,300/kW to US$3,500/kW. The average was about US$2,700/kW. Compared with other SHPP projects evaluated by Fichtner in other parts of the world, specific costs of projects assessed in the Western Balkan region are considered comparably low.

confirms IRENA results, while the mean 75 percent of the plants differ by only US$270/kW downwards and US$380/kW upwards from this and thus range between around US$1,350/kW and US$3,600/kW.

As in the IRENA study, outliers occur because some HPP construction occurs at sites without infrastructure and with limited access to transmission.

Individual groups of main cost items show a wide range of unit costs as reflected by the coefficients of variation, which are comparatively high for all groups. Starting with 0.47 for civil works costs and 0.49 for the E&M equipment, coefficients go up to 0.78 for project development. Relatively low coefficients of variation for E&M equipment are due to supply by international manufacturers at international market prices; the values differ primarily as a result of power plant size and technology. Despite huge variations in civil works across countries and project sizes, the civil works variation coefficient is relatively low. Wide ranges among individual groups of items level out to some extent at the aggregate level of total plant unit costs; the coefficient of variations is only 0.40 for total unit costs, the lowest of all values.

This wide range of unit costs reflects the individual nature of hydropower plants, and their incomparability due to variations in site, location, size, hydrology, geology and topography. The plant with the lowest unit costs per kW is the one with the highest installed capacity (1,200 MW) that was analyzed for this report. Furthermore, differing levels of development among the source data affected results. Box 13-1 presents a case study.

13.2.3 Benchmark of shares in total costs

13.2.3.1 Main CAPEX components

Table 13-4 figures confirm the importance of civil works; their share in total plant costs is 33.2 to 76.5 percent. Figure 13-4 shows the mean 50 percent of civil works costs are 47 to 61 percent of total plant costs. Furthermore, the mean 75 percent varies by only 7.7 percentage points down and 3.1 percentage points up, thus lying from about 40 to 64 percent. Generally HPPs with a dam exhibit a high share of civil works costs. These figures demonstrate that the share of civil costs in total plant costs can be determined comparatively clearly as it is affirmed by civil works comparatively low coefficient of variation of only 0.21.

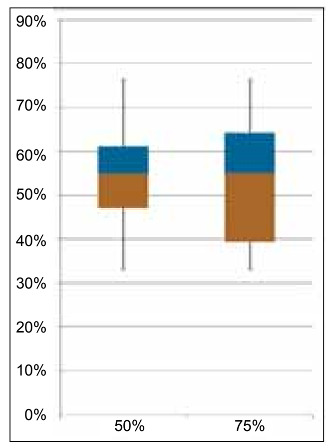
Electro-mechanical equipment (E&M) is the second important CAPEX component; it averages 30.3 percent of total project costs (Figure 13-5) but ranges from 14.9 to 56.6 percent, exhibiting wide cost variations similar to those of civil works.

Table 13-4: Share of main cost groups in total plant costs (%)

	Min	Median	Average	Max	Coefficient of variation
Project development	3.0	7.5	9.2	17.2	0.50
Civil works	33.2	55.2	54.3	76.5	0.21
E&M equipment	14.9	29.2	30.3	56.6	0.40
Other	0.1	1.2	1.3	2.3	0.53
Contingencies*	5.4	9.8	9.1	12.6	0.27

**At feasibility and prefeasibility level*
Source: FICHTNER

Figure 13-4: Range of civil works shares



Source: FICHTNER

The mean 50 percent of E&M shares range from 20.4 to 37.4 percent, and the mean 75 percent range from 17 to 46 percent.

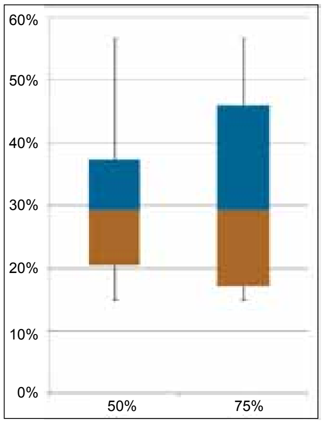
Costs ranges are wide for project development, engineering, environmental and social concerns due to variations in how project developers categorize expenses under this main component. Project development costs range from 3.0 to 17.2 percent of total plant costs, depending on which sub-items are included in this group. The median stands at 7.5 percent.

The last main item, *other,* captures all equipment and works that do not fit well in any other category; this varies by project, and since its overall share in total plant costs is low, it will not be further examined.

Contingency costs are important and often underestimated by project developers and consultants. Contingencies are applied to various cost items to cover uncertainties associated with their scope and cost. Price contingencies for potential price increases are not addressed since the CAPEX values are expressed in 2013 price values.

To compare the share of the contingencies this analysis considered 14 prefeasibility and feasibility reports (actual costs

Figure 13-5: Range of electromechanical equipment shares



Source: FICHTNER

no longer include contingencies). The contingency share of total plant costs appears below in Table 13-5.

Table 13-5: Share of contingencies in total plant costs

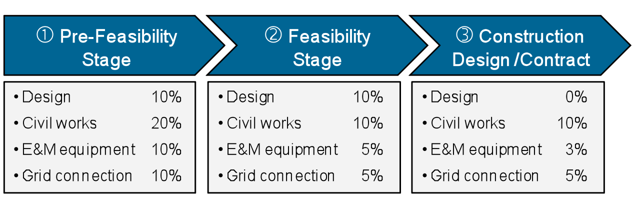
Min	Median	Average	Max
5.4%	9.8%	9.1%	12.6%

Contingencies average 9.1 percent of TPC; the median was 9.8 percent. The industry practice is to use 15 percent contingency for civil works costs, 7.5-10 percent for electromechanical equipment costs, and 7.5-10 percent for grid connection costs.

Civil works are among the most critical risk areas for cost increases, so provisions must be made to factor that in. For example, during feasibility studies final investigations into soil conditions have not yet been carried out, but soil conditions are a major cost-driver for civil works. The same holds true during the construction phase when the contract has already been signed with the civil contractor. The risks of cost increases are even higher if a tunnel must be built. Therefore an experienced geological expert should undertake individual risk assessments.

In practice, contingencies are adjusted throughout all project phases, but are typically higher during earlier phases when there are more unknowns as shown in Figure 13-6.

Figure 13-6: Contingencies



Source: FICHTNER

13.2.3.2 Grid connection

The main cost factor for grid connection is the distance between the plant and the existing grid. A remote plant with a long transmission line will incur very high costs so an HPP would be economically viable *only* at sites with highly favorable hydrological conditions to produce a high energy yield. However, if a grid connection is close to the plant, or facilities can be shared with other users, potential costs are substantially reduced.

Because grid connections costs are completely a function of the distance between the plant and the grid, the share of grid connection costs in total costs ranges from 0.3 to 8.7 percent (Table 13-6).

Table 13-6: Share of grid connection costs in total costs

Min	Median	Average	Max
0.3%	4.5%	4.1%	8.7%

Source: FICHTNER

13.2.4 OPEX Benchmark

Expenditures for operation and maintenance (OPEX or O&M costs) include staff costs, regular maintenance and spare parts, consumables, and insurance.

OPEX found in the documents used for this analysis also included concession fees, water utilization fees, or land lease charges, which varied by country.

Project developers and consultants have options for calculating OPEX for a power plant. Most OPEX are calculated as a specified percentage of total *plant* cost; or total *project* cost, which includes cost of financing. Another option is to compute OPEX cost based on installed plant capacity—costs per kW, or by using annual energy output (costs per kWh). Generally OPEX are considered less important than CAPEX because their contribution to production costs is much smaller.

Typically, OPEX cost estimates were not disaggregated by item, merely calculated as percentage (1.0 to 3.0 percent) of total project costs. Therefore, no real benchmark is possible nor is it advisable to calculate a benchmark of shares in total CAPEX. Thus OPEX estimates can be reasonably calculated only at a per-unit level. Similar to the CAPEX benchmark in the previous chapter, OPEX are calculated per unit of installed capacity in US$/kW using 2013 pricing.

Typically, O&M costs are disaggregated into variable and fixed costs, but most hydropower O&M costs are fixed. Therefore, O&M cost estimates include only one key figure, which captures both fixed and variable costs.

To complement the data set, O&M costs were also computed for projects without O&M costs in the related study, using a value of 1.5 percent of total project costs. This is reasonable since most of the OPEX analyzed are likely at the lower end of the benchmark range of 1.0-3.0 percent mentioned. Table 13-7 show the results. Not surprisingly, O&M costs per kW differ significantly especially with plant size and hydro type. OPEX costs in the 19 projects analyzed ranged from US$2.30/kW to US$64/kW. This extreme spread is likely due primarily to labor costs, which vary widely among countries. In addition, the spread results from the wide range of CAPEX unit costs, which are the basis for determining OPEX unit costs for most projects, as described. Moreover, the minimum value of US$2.30/kW is an exception and is far below the second lowest value. Both median and average are moderate figures, US$32.50/kW and US$33.20/kW installed capacity.

Table 13-7: OPEX unit costs

OPEX	Min	Median	Average	Max
US$/kW	2.3	32.5	33.2	63.9

Source: FICHTNER

The mean 50 percent of OPEX are between US$25.50/kW and US$45.10/kW in a narrow range around the median value. The mean 75 percent differ by about US$40/kW upwards and almost three times as much downwards, thus demonstrating a large range (Figure 13-7).

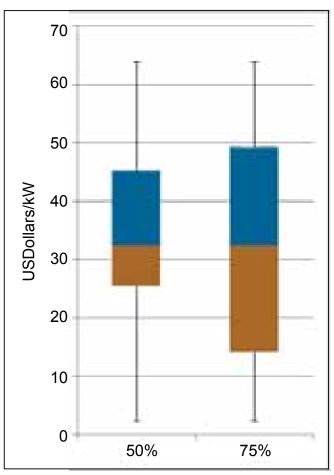
OPEX vary greatly among countries due to national labor cost differences however, in practice OPEX are set at a fixed rate (see Section 13.1), which depends on project size and technology. For example IEA applies 2.2 percent for large hydropower plants and 2.2-3.0 percent for small hydropower plants.

13.2.5 Benchmark of levelized cost of electricity

Levelized cost of electricity (LCOE) is defined as the ratio of the *net present value* (NPV) of total costs (CAPEX and OPEX) and the NPV of the energy produced over the entire plant lifetime (assumed to be 30 years). To calculate the NPVs a real discount rate of 8.0 percent is applied.

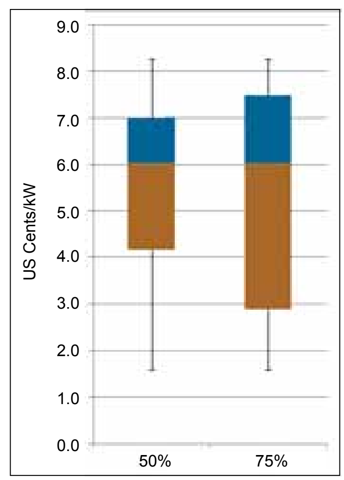
The LCOE is recommended as a first benchmark figure to assess project competitiveness and financial viability in the first stage of appraisal. If the LCOE is lower than the expected level of wholesale tariff (per kWh), the project is considered in principle to be financially viable. If the LCOE is higher than the expected level of wholesale tariff the project may be unable to achieve the necessary returns and therefore is not financially viable. More detailed analysis would be needed both on project costs and the power market. For example, the HPP may provide firm capacity and energy during peak demand times when electricity could be sold at a higher price. Also, other means of supporting the project (subsidies) or additional revenues (climate-related) may be available to make it financially viable (Figure 13-8).

Figure 13-7: Range of OPEX



Source: FICHTNER

Figure 13-8: LCOE variation



Source: FICHTNER

Table 13-8 shows that the LCOE of the HPPs analyzed have a comparatively wide range. The lowest value is 1.6 cent/kWh and the highest 8.3 cent/kWh, a factor of more than five between lowest and highest. The lowest value of 1.6 cent/kWh is for the largest plant with a total installed capacity of 1,200 MW, fully demonstrating economies of scale. However, economies of scale are generally not applicable, as the second lowest LCOE value is found for a small plant with an installed capacity of only 15 MW. The highest LCOE is observed for an HPP of similar size to the second lowest. The LCOE of these two plants vary by a factor of >3.

Average LCOE is 5.4 cents/kWh and the median is 6 cents/kWh. The mean 50 percent of the LCOE is in a narrow range from 4.2 cents/kWh to 7 cents/kWh. However, the range for the mean 75 percent is considerably wider between 2.9 cents/kWh to 7.5 cents/kWh, demonstrating the great variety among plants in average generation costs.

Table 13-8: Levelized costs of electricity

LCOE	Min	Median	Average	Max
USCents/kWh	1.6	6.0	5.4	8.3

Most hydropower projects provide relatively inexpensive power and other benefits to local communities, such as jobs.

14 Economics and Financial Analyses

The decision to implement a proposed project is based on detailed assessment of all factors that could affect the project—technical, institutional, environmental and social, economic and financial.

Financial and economic analyses serve different purposes but both are needed especially in large hydro projects (see Box 14-1). Smaller projects with feed-in-tariffs (FiT) may not require an economic analysis because the process of developing a FiT should have taken into account all economic considerations. Differences between small and large hydro schemes appear in Box 14-2.

Box 14-1: Economic vs. financial analysis

Financial Analysis

- Conducted from an investor perspective
- Uses market prices to determine project financial viability and sustainability No externalities included such as environmental benefits and costs

Economic Analysis

- Economy-wide/society perspective
- Uses economic prices (values) derived from market prices by excluding taxes, subsidies, profits and tariffs to reflect the real value of the project to society
- Externalities such as environmental benefits and costs are included
- Crucial for large hydro projects; might be unnecessary for small projects

Box 14-2: Differences between small and large hydro projects

Several significant differences that exist between small and large hydropower plants are important when conducting financial and economic feasibility analyses.

First: The per kilowatt investment costs might be lower for large hydropower plants than for smaller ones due to economies of scale (see Section 3 for details). IRENA estimates the average per kW investment cost of small HPPs to be 1,300-8,000 US$/kW. For large HPPs, IRENA estimated average per kW investment costs are 1,050 to 7,650 US$/kW.

Second: Some small hydropower projects are evaluated as a single-purpose, non-essential project. Therefore, such projects will have fewer or different benefits than larger facilities that can be justified by benefits such as flood control and recreation, among others, in addition to increased power provision.

Third: Many small hydropower projects are designed as run-of-river plants, implying that no ability to store water and schedule peak power generation (firm capacity).

Fourth: In many countries, small hydropower plants are developed under a feed-in-tariff (FiT) scheme, i.e., any output will be purchased at a specified price. Larger HPPs often supply their power under a PPA, if permitted under the market model.

The financial analysis evaluates potential profitability from the perspective of an investor by examining project benefits and costs to an enterprise. A profitable project must have an equal or higher return than a hurdle return on investment. The investor requires a higher return on investment if risks are higher, however, investors have different perceptions of risk. Therefore, the hurdle return rate reflects the investor's perceived project risk.

The economic analysis adopts a macro perspective and evaluates the project benefits to the economy and society by comparing two scenarios—*with* the project and *without* the project. In addition, economic analysis includes externalities.

Additional information on economic and financial analyses can be found in the World Bank publication, "Economic Analysis of Investment Operations: Analytical Tools and Practical Applications;" and in the Asian Development Bank publication, "Guidelines for the Economic Analysis of Projects."[11]

14.1 Financial analysis

The financial analysis evaluates overall project financial viability of a project. Financial analysis for hydropower projects can be challenging for the following reasons:

- Hydrology: Power generation depends on water flow, which is affected by weather conditions and seasonal variations. Therefore, power generation and income from power sales are variable and uncertain (especially for run-of-river projects).
- Hydropower projects entail high front-end costs and high construction risks, but operating lifespans are long and operating costs are low.
- On the positive side, hydropower project cash flow is not vulnerable to coal and gas price fluctuations because it does not use fuel.

The following section describes typical key assumptions for a financial analysis; it explains important output indicators and provides practical examples for context.

11. Full references for World Bank and ADB Economic Analysis are listed in Section 16.

14.1.1 Key Assumptions

Table 14-1 presents an overview of financial analysis core assumptions for hydropower plants of any size and technology.

Financial analysis is conducted from the investor perspective and evaluates project impact on investor cash flow. Financial analysis does not consider any external effects such as environmental and social considerations, unless they delay construction and affect costs, they can be monetized and provide a revenue stream to the project.

Table 14-1: Financial analysis assumptions

	Financial analysis assumptions
Analysis perspective	Project sponsor or lender
Evaluation period	Financial life of project (varies)
Adjustment for inflation	Includes inflationary effects
Project input valuation	Project costs are valued using their purchase costs, i.e., market prices
Discount rate	Financial discount rate; financial rate of return (including inflation) that could be expected if money were invested in another project, based on typical average cost of capital for a similar project (WACC)
Interest paid on borrowed funds during construction	Included

Source: FICHTNER

As Table 14-1 describes, the financial rate of return is the discount rate that could be expected if money were invested in the next best project option (opportunity cost of capital). The appropriate discount rate is referred to as the weighted average cost of capital (WACC). The WACC is defined as the after-tax weighted average of an investor's entire source of finance such as common stock, retained earnings, preferred stock and debt. Generally, deriving investor WACC can require multiple complex calculations, but in essence WACC calculation is as follows:[12]

$$\text{WACC} = \text{Weight of Equity} \times \text{Cost of Equity} + \text{Weight of Debt} \times \text{Cost of Debt}$$

…where the value of debt is calculated as after-tax value.

Furthermore, several issues must be anticipated regarding HPP financial analysis assumptions, which will be outlined below (see Box 14-3).

Revenue

Larger hydro facilities supply power under a purchase price agreement (PPA) or based on wholesale market prices, depending on the national market model. In countries with multilateral or competitive market models, large hydropower plants often supply base power because their marginal costs are relatively low. However, storage hydro plants and in particular pump storage plants, are able to provide peak power by pumping stored water during off-peak periods and releasing that water during peak periods. This creates additional tariff benefits because pump storage plants can cash in the price difference between peak and off-peak tariffs, if such a differential exists in the market model.

The output of most small hydropower plants is taken off under a feed-in-tariff scheme (FiT), which guarantees a fixed price for electricity produced by a renewable energy source such as SHPP over several years. Cost differences between the market price and the feed-in-tariff may be recovered from consumers through a supplement on the retail price, or recovered through other sources such as taxes.

Most PPAs and feed-in-tariff schemes are shielded from market fluctuations since the agreements include negotiated or fixed prices. Instead, market risk is passed to the off-taker. Merchant plants—independent power plants (IPPs) without a PPA—must sell electricity at their own risk, particularly in deregulated markets in which electricity is purchased in a competitive market at varying volumes and prices.

In addition to the two examples given above, several other schemes exist. For example, regulated tariffs could be established on a project-by-project basis, negotiated tariffs with one or more off-takers, or market-based incentives for renewable energy such as renewable energy credits, the price of which varies with the market.

The financial analysis must consider how the tariff regime under which the plant sells its power will affect cash flow. For example, merchant plants have volatile revenues because they sell varying volumes at varying prices; income varies according to whether a plant provides base or peak power.

Hydrology

Hydrology determines how much water will be available for electricity generation throughout the year, based on historical seasonal rain patterns and geography. Hydrological study results are essential for the financial analysis since plant operation is

Box 14-3: Why do discount rates matter?

The choice of discount rate (economic and financial) affects the present value of future costs and benefits, thereby affecting project return and profitability.

Hydropower plant investment costs are high operating costs are low, implying that under a lower discount rate, hydropower development is favored. Thermal plants require less capital expenditure at the beginning of development, which means thermal development is favored under a higher discount rate (i.e., more cash is available to put in the bank).

For example, consider two alternatives. The first is an HPP with storage and a capacity equivalent coal-fired power plant under a discount rate of 10 percent. Depending on the CAPEX of both projects, yet, assuming that the CAPEX of the HPP are higher, the TPP will most likely yield lower levelized unit costs (LUC) than the HPP (the concept of LUC is outlined in Section 14.1.2).

However, if a discount rate of 5.0 percent were to be applied, the LUC of the HPP potentially could fall below the LUC of the TPP. Therefore, the HPP would be more profitable under a lower discount rate as opposed to a discount rate of 10 percent.

12. For further information please consult:
Armitage, Seth. The Cost of Capital: Intermediate Theory. Cambridge, UK: Cambridge University Press, 2005.
Johnson, Hazel. Determining Cost of Capital: The Key to Firm Value. London: FT Prentice Hall, 1999.
Pratt, Shannon P., and Roger J. Grabowski. Cost of Capital: Applications and Examples. 4th ed. Hoboken, NJ: Wiley, 2010.

crucial to project financial viability. Hydrology determines the optimal size and average load factor for a hydropower plant, which summarizes how much electricity can be produced throughout the year with a specific installed capacity. Therefore, hydrology's stochastic nature makes it essential to assess project sensitivity to annual energy yield fluctuations and to predict how much electricity can be sold throughout the year, because project cash flow will be volatile.

Hydrology is affected by climate change impacts (rain patterns, water flows), which has potential to increase uncertainties connected to water flows and hydrology. Section 14.3 provides more detail on hydrology based on which sensitivity analysis could be carried out to assess the impacts on financial parameters.

Economic lifespan

Hydropower plants can have an operating lifespan of up to 50 years or more, which is quite long compared to thermal power plants. Typically economic and financial analyses assume a lifespan of 30–40 years.

Hydropower plants' cost structure includes high capital costs and low operating costs compared to thermal plants, which have smaller investment costs but higher operating costs due to fuel use. This implies that hydropower projects have longer-term benefits and therefore may seem less attractive if the analysis period chosen is too short.

Therefore, even though the period selected for the financial analysis may be shorter than that considered for the economic analysis, it should still be long enough to capture longer-term project benefits.

In addition, the financial analysis should consider residual values of the HPP if the analysis period is shorter than the plant operating lifespan.

Capital costs

Hydropower plant capital costs are frequently subject to cost overruns or project delays; this risk is mitigated through contingencies, discussed in Section 13. Capital costs can increase due to environmental or social considerations, such as resettlement. Because these sources of cost overrun are common, a conservative financial analysis is recommended to take into account all potential cost increases.

In addition, capital costs should be subjected to sensitivity analysis to derive the effect of varying costs on cash flow. This is discussed in Section 14.3.

14.1.2 Financial analysis results/outputs

Typically, financial analysis is conducted through complex custom spreadsheet models to calculate financial viability and cash flow under a range of financing assumptions. The investor must determine financial performance, based on the following financial modeling outputs:

- **Financial net-present value (NPV):** The NPV is a stream of annual cash flows generated by the project over a given time period discounted by a pre-specified discount rate (i.e., time value of money) to a single value. Within the context of the financial analysis, the appropriate discount rate to derive the net-present value is the WACC.

$$NPV(i,N) = \sum_{t=0}^{N} \frac{C_t}{(1+i)^t}$$

...where i is the financial discount rate (WACC), Ct the net cash flow at time t and N the total number of time periods.

NPV is a central tool in discounted cash flow analysis and is a standard method for using the time value of money to appraise long-term projects. Used for capital budgeting and widely used throughout economics, finance, and accounting, NPV measures the excess or shortfall of cash flows, in present-value terms, after financing charges are met.

NPV can be described as the difference between total discounted cash inflows and cash outflows. NPV compares today's present value of money to the future's present value of money, taking inflation and returns into account. The NPV can also be derived for only the equity share of the investment (discounted with cost of equity).

- **Levelized cost of electricity (LCOE):** The LCOE[13] is defined as the NPV of all costs divided by the NPV of electricity generation. In essence, the LCOE is the constant price per unit of energy that allows the investment to just break even over the period of analysis. Broadly speaking, the lower the LCOE, the more profitable the project will be (See example in Box 14-4).

- **Financial internal rate of return (FIRR):** The internal rate of return (IRR) on an investment or project is the annualized effective compounded return rate or rate of return that results in a zero net present value of all cash flows (positive and negative).

Specifically, the IRR of an investment is the discount rate at which the net present value of investment costs (negative cash flows) equals the net present value of investment benefits (positive cash flows).

Generally, an investor seeks a project with a high IRR compared to other investments in the same (risk) category or sector.

The FIRR can also be derived net of financing, called pre-tax FIRR on equity. The equity FIRR should be larger than the opportunity cost of equity.

- **Debt service coverage ratio (DSCR):** This is the ratio of cash available for debt servicing of interest, principal and lease payments over the financing period. It is a benchmark used to measure an entity's ability to produce enough cash to cover its debt (including lease) payments. The higher this ratio is, the lower the investors' risk. Lenders will demand that the DSCR be >1 by some margin to be confident that the debt can be repaid.

$$\text{Debt service coverage ratio} = \frac{\text{Net operating income}}{\text{Total debt service}}$$

13. Sometimes referred to as Levelized Unit Costs (LUC).

Box 14-4: LCOE example

This example will describe the derivation of the LCOE for a hydropower project, using the following variables as inputs:

- Annual power generation: 342 GWh per year
- Installed capacity: 66 MW
- Investment costs (CAPEX): US$165 million
- O&M costs: 1.2 percent of CAPEX per annum
- Construction period: 4 years with equal cost disbursement
- Lifespan: 60 years
- Discount rate: 10 percent

The table below presents the basic time series calculation to derive net present values of generation and total costs. Typically this would be calculated for all 60 years of project lifespan, but the table provides only an example.

		Construction period in years		Operational period in years		
		1	4	5	2	64
Elect. Gen.	GWh/a	0	0	Power generation per year=342	342	342
CAPEX	m$/a	Capex/Const. Period = 41.25	41.25	0	0	0
Opex	m$/a	0	0	1.2% x US$165 million (CAPEX) = Opex per year = 1.992	1.992	1.992
Total	m$/a	Capex + Opex = Total = 41.25	41.25	1.992	1.992	1.992

On the basis of the table above the net present value regarding total costs (CAPEX+OPEX) can be calculated with a discount rate of 10 percent according to the following:

$$NPV_{Costs} = \sum_{t=1}^{64} \frac{Total\ \text{costs}_t}{(1+10\%)^t} = 144.32m\$$$

Similarly the net present value for the electricity generation can be calculated according to the equation below:

$$NPV_{Gen.} = \sum_{t=1}^{64} \frac{Generation_t}{(1+10\%)^t} = 2328.23\ GWh$$

Once net present values have been derived, the levelized unit costs or long run marginal costs can be derived:

$$LUC = LRMC = \frac{NPV_{costs}}{NPV_{Gen.}} = 0.06 * 100 = 6\$cent/kWh$$

If a DSCR shortfall is forecast or if it occurs, a Debt Service Reserve Account, designed to cover this shortfall, may be required.

The DSCR is particularly important given the hydrology implications; debt should be structured to address seasonal variations, so that the DSCR is covered in dry months.

- **Discounted payback period:** This is the period needed to recoup initial capital investments; the shorter, the better.

Illustrative examples are given in Box 14-5 and Box 14-6.

14.2 Economic analysis

Economic analysis is conducted primarily in response to a request by the country in which the project will be located, or an international financial institution such as development banks. However, for large hydro projects especially in case of

Box 14-5: Typical benchmarks for key financial parameters on SHPP projects

Some financial attractiveness and eligibility criteria from Best Practice SHPP Projects are presented below:

- Internal Rate of Return on the project—(IRR) over 10 percent
- Net Present Value on the project—(NPV) equivalent to at least 25 percent of the investment. It should be expected that the Discount Rate—or Weighted Average Cost of Capital (WACC) feed into NPV—should be 9.0 percent or higher (depending on market interest rate level).
- Simple Payback Time (SPT)—Ideally fewer than 10 years for a SHPP project, but varies from market to market and can vary from 10–15 years
- Debt Service Cover Ratio (DSCR)—usually in the range of 1.2–1.5

Exact criteria are subject to discretion and decided upon in each case based on complete financial due diligence and financial structure. Domestic benchmarks for these criteria often depend on the economy's underlying interest rate, country risk and general level of economic development, and are subject to changes over time.

Box 14-6: Financial analysis example: Large hydropower in Vietnam

The project under consideration is a large hydropower facility at the Ma River, Quan Hoa district, Thanh Hoa province in northwestern Vietnam. The project is designed with an installed capacity of 250 MW.

Key Assumptions

- Six years construction /two years partial operation/39 years full operation
- US$349 million CAPEX/ O&M costs of 1.5 percent of CAPEX
- Energy output is 1,019 GWh per annum
- WACC is 4.7 percent

Results

- FIRR is 6.46 percent, which is larger than the WACC of 4.7 percent
- LUC are US$0.0289, which is smaller than average generation costs of US$0.031

Conclusion

As the FIRR rate of return is larger than the WACC, the project is profitable from a financial viewpoint.

negotiated tariffs, economic analysis is essential and provides all stakeholders (including developers) with valuable insights on the value of the project to the economy.

Economic analysis evaluates project costs and benefits from the perspective of the economy/society. Benefits and costs (transnational, national and regional) including project external effects are quantified and expressed in monetary terms to derive the economic net benefit.

The following section provides more information on the assumptions underlying the economic analysis, some of which overlap with the financial analysis. The section will outline significant output indicators and present a case study to illustrate a practical application of economic analysis.

14.2.1 Assumptions

Table 14-2 below provides an overview of general assumptions for economic analysis of hydropower projects.

Table 14-2: Economic analysis assumptions

	Economic analysis assumptions
Analysis perspective	State, and/or national and community perspective
Evaluation period	Economic life of project, i.e., until decommissioning
Adjustment for inflation	Exclude inflationary effects; price changes different from inflation can be included (escalation)
Project input valuation	Project inputs valued using their economic opportunity costs, derived by excluding taxes, tariffs, subsidies, etc.
Discount rate	Economic discount rate; real rate of return (excluding inflation) that could be expected if money were invested in another project
Interest paid on borrowed funds during construction	Not included (financial cost)

Source: FICHTNER

The discount rate appropriate for economic analysis is the economic discount rate, which is the rate of return or interest rate of the entire economy, i.e., the national opportunity cost of capital. In comparison, WACC is applicable only to an individual investor since the WACC calculation is based on a single investor's cost of equity and debt.

Project costs and benefits are valued at economic prices that exclude taxes, subsidies, import duties, etc., as these costs do not add to economic productivity and are merely transactional in nature.

In addition to the assumptions above, the hydro-specific assumptions made under Section 14.1.1 apply equally to the economic analysis.

Some projects can produce substantial macroeconomic benefits including for communities near the construction site, such as jobs and lower electricity costs. In the following section, benefits and costs are elaborated from a communal and macro perspective, respectively.

14.2.1.1 Local economic benefits and costs

Most hydropower projects provide relatively inexpensive power and other benefits to local communities. Local benefits should be weighed against negative impacts.

Local economic benefits from hydropower plants include the following:

- Creates local jobs and trains workers
- Develops infrastructure, such as roads and electricity
- Improves local services, such as enhanced water supply, schools and healthcare facilities
- Boosts agricultural productivity and marketing, for example through enhanced irrigation systems
- Promotes other business activities
- Increases fishing opportunities (difficult to quantify)
- Boosts tourism and leisure opportunities (difficult to quantify)

Local economic costs from hydropower development are incurred mainly by larger facilities, and include:

- Requires human resettlement (among the most prominent costs)
- Requires environmental and social mitigation (among the most prominent costs)
- Diminishes local resources during construction, i.e., local communities face fewer resources, such as electricity (difficult to quantify)
- Opportunity cost of land used for HPP development

14.2.1.2 Public economic benefits and costs

Hydropower projects can provide a substantial boost for the macro economy, depending on the national power market context, and can provide a host of other macroeconomic benefits such as:

- Lower electricity costs represented by the difference between hydro generation and the next best power alternative. Hydro option avoids fuel-cost volatility and features a long lifespan.

- Reduced electricity rationing (load shedding) due to increased capacity (if applicable), calculated as "cost of electricity not served"
- Increased investment and national income due to providing cheaper and more reliable electricity, calculated using regression analysis and a dataset of similar projects
- Reduced reliance on imported fossil fuels, less need to accumulate foreign currency, hence lower currency risk for national economy
- Possible increased support for rural electrification programs
- Reduced greenhouse gas emissions
- More environmental benefits from reducing alternative fossil fuel-based electricity generation
- Reduced health costs and better overall air quality from pollution externalities, using regression analysis, if data are available
- Downstream benefits such as irrigation, water supply, flood mitigation, increased potential for water-based transport, increased ability to regulate additional downstream hydropower plants (if applicable and can be difficult to measure)
- Increased tax payments to government

National benefits must be evaluated against their costs. Typical macro costs for hydropower projects, depending on plant size, include the following:

- Land acquisition costs, calculated as real economic value of land, including opportunity cost
- Capital expenditures and operation and maintenance costs; disaggregated into shares of national currency and foreign currency, also, potential risk posed by foreign currency exposure to exchange rate volatility
- Costs incurred due to design, investigation, monitoring, adaptive management, planning and sighting
- Capital and service costs related to environmental and social mitigation
- Costs related to replacing major equipment or major civil works
- Subsidies if needed

Not all regional/national costs and benefits apply to every hydropower project however, any of the above costs and benefits that are at hand and quantifiable should be included in the economic analysis to capture the largest possible context. Box 14-7 illustrates the economic costs of sedimentation.

Box 14-7: Economic costs and sedimentation

Reduced project lifespan due to externalities

Sedimentation remains one of the most severe problems faced by storage hydropower projects. Small particles that are carried along in the flow of the river accumulate and settle in the stilled dam area. As more sediment accumulates, dam storage capacity declines and the river downstream from the dam carries less sediment than before the dam was installed. This situation has severe implications for project economic costs since sediment accumulation reduces project lifespan through turbine abrasion, i.e., increased wear on the turbine from sediment entering.

This happened at the Warsak Dam Project in Pakistan; during periods of high flows sediment entered the intake structure of the dam and led to rapid turbine deterioration. Originally, the plant was designed to evacuate sediment through the spillway; but water flow during high flow periods was underestimated.

Adverse impacts

Sediment is bad for turbines but beneficial for agriculture because it carries nutrients important for fertilizing plants and soil. When a dam blocks the flow of sediment, agriculture suffers an economic cost, which is what happened in Egypt with the Aswan Dam. Before the dam was constructed, the annual flooding of the Nile River contributed to soil fertility due to the nutrients carried in the sediment. After the dam was constructed, soil fertility suffered and crop yields were reduced.

Therefore, sedimentation incurs two types of economic costs for large storage hydropower projects: (i) reduced project lifespan, and (ii) reduced agricultural production.

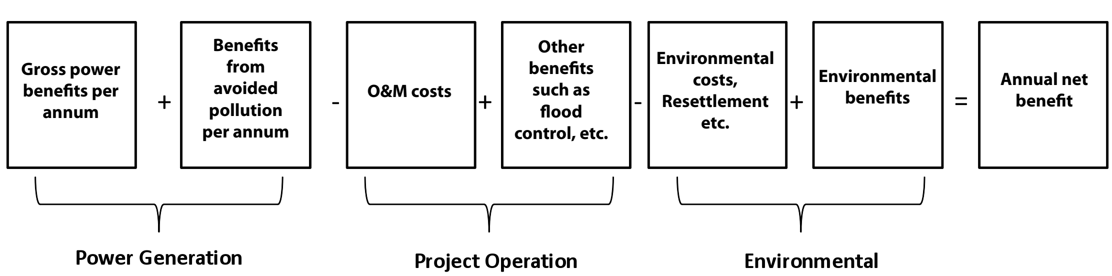
14.2.2 Economic analysis results/outputs

Once costs and benefits have been identified and are expressed in monetary terms, the economic net benefit is derived as illustrated below in Figure 14.1.

Project viability can also be assessed using the following indicators, which have the same underlying logic as the indicators outlined in Section 14.1.2 (see also Box 14-7 for example):

- **Economic net-present value**
- **Economic levelized cost of electricity**
- **Economic internal rate of return:** As mentioned in **Section 14.2.1**, for the economic analysis, the economic internal rate of return should be compared to the economic discount rate (not to the WACC, as was the case for the financial analysis).
- **Economic cost/benefit ratio:** Compares the monetary value of total benefits to the monetary value of total costs. The ratio should be larger than one, indicating that project benefits outweigh the costs.

Figure 14-1: Derivation of economic net benefit



Source: FICHTNER

Box 14-8: Economic analysis example: Large hydropower in Vietnam

The Ma River large hydropower project in Vietnam illustrates the following:

Benefits

- Power and electricity: Measured as avoided costs, i.e., in the absence of the Ma River project, other projects would be developed to meet the demand. Therefore, the benefit is quantified by estimating the marginal value of coal and gas-fired power production and the value of avoided thermal capacity.
- Reduced CO_2 emission
- Avoided generation costs: avoided variable costs of thermal power production
- Reduced dependency on thermal fuels
- Increased agricultural productivity
- Improved flood control

Assumptions

In addition to the assumptions made under the financial analysis, the following assumptions are valid for the economic analysis:

- Inflation of 2.7 percent (OECD) and 5.0 percent (local)
- Capacity benefit of $1,116/kW
- Flood control benefit at around US$5.4 million
- Economic costs exclude value-added taxes and contingencies
- Loss of forest value at US$8.0 million
- Economic discount factor at 12 percent

Results

- The EIRR of 19 percent is larger than the discount rate
- The project exhibits economic levelized electricity costs of US$0.05/kWh with a net present value of US$361 million.

Conclusion

The project is economically feasible and the project guarantees economic sustainability. Project benefits outweigh project costs, thereby contributing to national economic development.

14.3 Sensitivity analysis

The sensitivity analysis varies essential parameter inputs for financial and economic analysis, while all other variables remain constant, ceteris paribus. Uncertain parameters/inputs are identified and the effects of their variations on key outcomes help determine the amount of contingency that should be included in project investment (see Box 14-9 for example).

Typically, the effects of input parameter variations are monitored through:

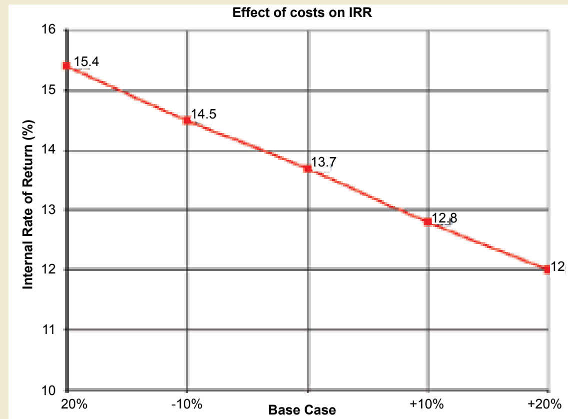
- IRR (financial and economic)
- LCOE (financial and economic)
- Debt service coverage ratio

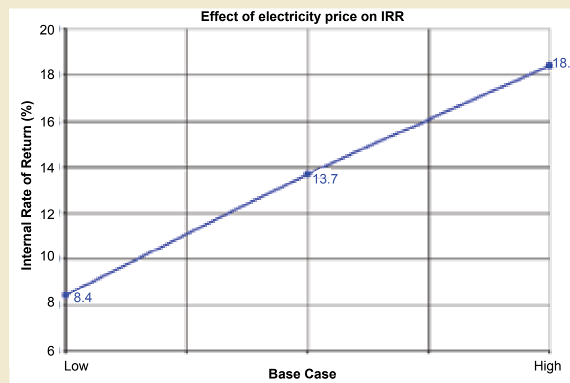
Typical parameters subjected to sensitivity analyses are the following:

- **Investment costs:** Typically varied by ± 10 percent, reflecting under- or overestimation of work magnitudes or unit prices (variations can be increased or decreased depending on project size and national context). The variation interval should be increased when evaluating the project at a very early stage because of higher risk and increased uncertainty.
- **Construction delays:** due to adverse weather conditions or other impediments to project implementation according to schedule
- Alternative economic and financial **discount rates**

Box 14-9: Sensitivity analysis example

Below are two examples of sensitivity analysis outputs with respect to costs and electricity prices.





Source: FICHTNER

Tariffs

- **Environmental mitigation costs**

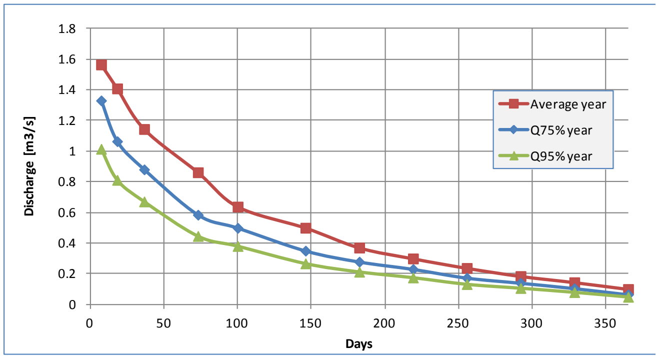
Hydrology variations affect project profitability because revenue from electricity sales declines during dry years. Consequently, investors should conduct probability estimations during the financial analysis, in particular cash flow analysis. Dry years reduce net operating income and could reduce investor ability to service the debt. Therefore, an investor would demand a DSCR of greater than one to ensure profitability even if dry years occur frequently. Hydrology should be subjected to sensitivity analysis due to its stochastic nature.

To analyze hydrology sensitivities, the probability and impact of dry years is calculated.

- *Dry year, 75 percent (P75)*: this is the annual energy production which is reached with a probability of 75 percent;
- *Very dry year, 95 percent (P95):* this is the annual energy production, which is reached with a probability of 95 percent.

Using the definition of relative dry years helps derive flow duration curves for average years, and for P75 and P95 years, as seen in Figure 14-2.

Figure 14-1: Impacts of hydrology on water discharge
Source: FICHTNER



Flow duration curves and their underlying probability distributions help derive annual electricity generation for average years, P75 and P95 which offers valuable insight into generation capacities during bad years compared to generation capacity during average years.

14.4 Conclusion

Financial and economic analyses serve different purposes but both are needed especially in large hydro projects. However, there are some common pitfalls and issues to anticipate (see Box 14-10).

- Financial and economic analyses help determine HPP project attractiveness and viability.
- Financial analysis uses the following parameters:
- Financial internal rate of return (IRR)
- Financial levelized cost of electricity (LCOE)
- Debt service coverage ratio
- Simple payback period

Economic analysis investigates project feasibility from the perspective of the economy and society by comparing local and public costs and benefits. Typical parameters include the following:

- Economic IRR
- Economic LUC
- Economic cost/benefit ratio

The sensitivity analysis reveals the impact of variations to input parameters to derive overall robustness of the analyses towards change.

Box 14-10: Common pitfalls and issues to anticipate

- Financial and economic analyses have a high degree of explanatory power but are only as good as their underlying assumptions.
- Many underlying assumptions such as demand forecasts and price forecast are subject to a high degree of uncertainty and should be treated as a 'best guess extreme caution.
- Accurate estimates of financial costs and investment costs are deemed necessary and should be done under due diligence. Cost estimates are frequently undervalued due to unforeseen scope adjustments, procurement efficiency and local capacities.
- Hydrology is among the most critical parameters to consider, including in the cash flow analysis due to the potential impact it could have on the debt service covering ratio.
- The long operational lifespan of hydropower plants should always be taken into consideration, distinct from thermal alternatives.
- Environmental and social issues must be considered during HPP project development, in particular resettlement and its associated costs, which could be substantial.
- Successful HPP development requires a well-developed communications strategy, and early and continuous engagement with stakeholders, in particular the local community.

A major consideration in financing hydropower schemes is that high up-front capital costs can make them less attractive in the short term, but this is offset to a degree by long operating lifespans and low operating costs that provide significant long-term benefits.

Financing HPP Projects

15

Financing hydropower projects is complex due to hydro-specific characteristics such as hydrology, potential for cost overruns and delays, and long-term benefits. This section will discuss available financing schemes, in particular those suitable for risks common to hydro projects.

For more information on hydropower (project) financing, see the following resources:

- Head, Chris (2000) "Financing of Private Hydropower Projects," World Bank Discussion Paper 420, 2000. The paper provides details on the hydro financing process, financing arrangements and a broader context such as regulatory framework, off-take contracts and project implementation.
- Head, Chris (2006) "The Financing of Water Infrastructure: A Review of Case Studies," World Bank, 2006. This paper covers economic and financial viability, project risks, bankability and financing instruments.
- Plummer, Judith (2011) "Options Assessment for Structuring and Financing new Hydropower in PNG" PPIAF, 2011. The paper covers financing options under Public-Private-Partnerships in Papua New Guinea.

Box 15-1: Financing small hydro

Small hydropower projects might be less profitable, therefore more difficult to finance than larger projects. Many hydropower cost components are fixed regardless of project scale so larger hydro facilities offer economies of scale–the larger the facility, the lower the costs. For example, a typical feasibility study might account for 1.0-2.0 percent of total costs of a large hydro facility; for a small hydro plant the study might account for 5.0 percent of total cost.

In addition, most small facilities are designed as run-of-river so output depends on the water flows, which can vary seasonally and annually, creating revenue uncertainty. Therefore small hydropower plants are highly cost-sensitive; the impact of unforeseen costs is higher.

Consequently limited-recourse project finance (see Section 15.3.1) is difficult for small hydro plants without support mechanisms such as Feed-in-Tariff (FiT) schemes and standardized contracts such as PPAs, concession agreements, or step-in-rights.

15.1 General financing considerations

Hydropower project financing is complex because it is highly dependent on hydrology and uncertain water flows imply uncertain electricity generation and income. Financing must be structured to mitigate this risk. Hydropower project financing schemes must take into account the potential for frequent cost overruns, delays, and any potential resettlement that could increase capital costs. Also, a major consideration in financing hydropower schemes is that high up-front capital costs can make them less attractive in the short term, but this is offset to a degree by long operating lifespans and low operating costs that provide significant long-term benefits.

Characteristics of hydro power plants include the following:

- **Site-specific.** Each hydro project is unique and several alternatives exist to develop a potential hydro site.
- **Construction.** Construction periods are long and risks are high due to local geological conditions, flooding, lack of site access, and other risks.
- **High proportion of civil works.** This increases risk because final cost predictions are highly uncertain, particularly in countries with high inflation rates.
- **High capital costs.**
- **Long plant lifespan** of around 50 years.
- **Hydrology.** Power output can be unpredictable due to the stochastic nature of water flows, in particular for run-of-river plants.
- **Environmental/social considerations.** Hydropower development requires considerable investment in communications and mitigation measures for E&S.
- **Externalities.** Larger facilities can provide multiple benefits such as flood mitigation, irrigation, aquaculture, reserve drinking water supply and recreational potential, among others.

These characteristics have direct implications on the financing package: Long-tenor private finance is essential since hydro development costs are front-loaded and its technical lifetime is long (see Box 15-2).

- High construction risks require well-planned mitigation measures and risk-sharing arrangements to attract financiers and keep tariffs low. The EPC contract is a critical component of risk sharing.
- Long-term off-take agreements will make hydropower projects more attractive to private investors to compensate for the fact that generation and power sales are variable due to water flows' stochastic properties.

15.2 Financing options

This section discusses financing options for hydropower projects.

15.2.1 Project vs. corporate finance

Corporate finance. A lending institution offers financing to corporations that will implement the hydro project and assume responsibility for debt servicing—interest and capital repayments. The lender focuses on the corporation's ability to service the interest and repay or refinance the debt.

Project finance. The focus is hydro project bankability because the project, or the project-company will rely on project-generated cash flow alone to cover lender obligations. Under this scheme, project assets may serve as collateral to reduce lender risk. For example, sales agreement proceeds (off-take agreements), or shares pledged in the project company or that project physical assets could become the property of the lender in case of repayment default.

Figure 15-1 highlights key differences between project and corporate finance.

The key advantage of project finance is that it limits investor exposure to the project assets and safeguards their other assets. The opposite is also true; if project investors go bankrupt, the project company is not affected.

A corporate finance scheme could be beneficial if a project has small capital requirements and high financial viability, despite the difficulty of estimating cash flows.

15.2.2 Key Players

Figure 15-2 presents the key stakeholders in HPP project finance.

The cast of players varies depending on HPP complexity, but usually includes the following:

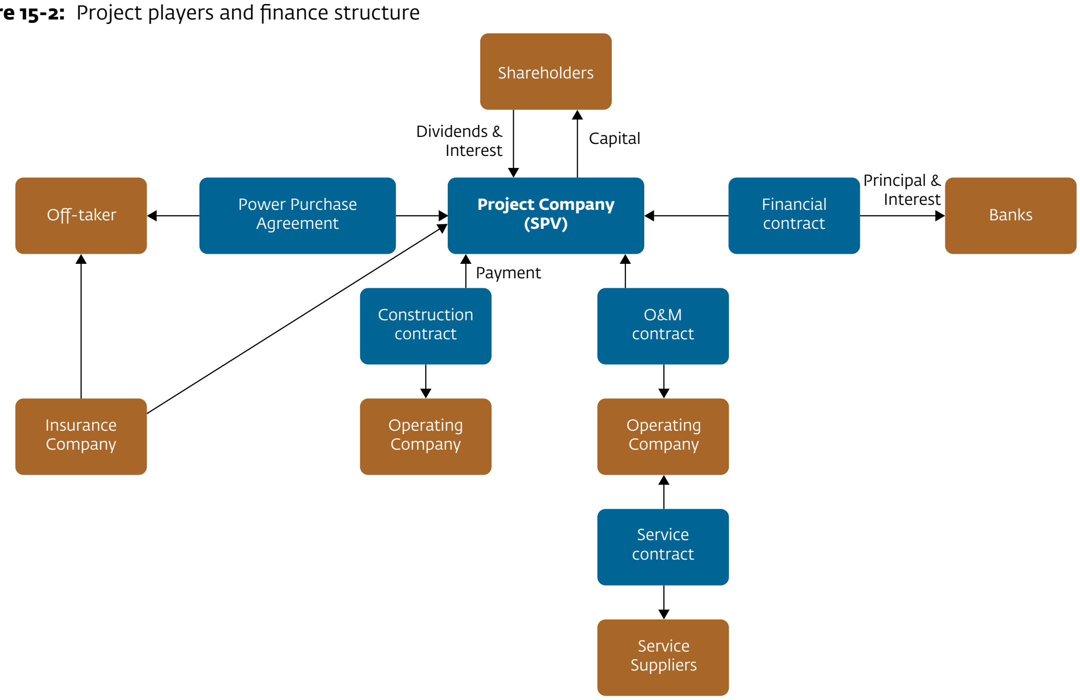
- **Sponsors or SPV shareholders.** A Special Purpose Vehicle (SPV) is established by the investors. The majority shareholder is usually the main sponsor who is running the project.

Figure 15-1: Project vs. corporate finance

HPP Financing	
Project Finance	**Corporate Finance**
Cash Flow Projection	
Is known before disbursement	Less relevant
Control & Monitoring of Cash Flow	
Very close	Can be performed if needed
Collateral	
The HPP itself	Non-project related collateral
Control over Collateral	
Very close	Not so tight
Leverage to Sponsor in case of multiple HPPs	
Enables multiple lending as only project assets are used as guarantee	Limited to sponsor's other assets and wealth
Type of Financing	
Non-recourse	Recourse
Credit Risk	
On HPPs cash flow (easy to estimate)	On sponsor's other businesses' cash flow (hard to estimate)
Start-up Financing	
Yes	No

Source: FICHTNER

Figure 15-2: Project players and finance structure



Source: FICHTNER

- For larger hydropower facilities, the national government or a government agency is often the sponsor; or the private sector could be involved through a PPP scheme.
- For small HPP projects, private investors are often the sponsors.

- **Lenders.** Normally a financial institution (bank) will provide most of the debt resources needed. For larger projects with higher risk, it is common for more than one bank or financial institution to provide funding to spread the risk among them. Lenders are typically categorized as follows:
    - International commercial banks
    - Local banks (rarely provide long-term financing)
    - Development banks or multilateral financing institutions (e.g., IFC, KfW, EBRD, ADB, AfDB, IDB, EIB, GGF, among others)
- **Off-taker.** Typically this is a national or regional power utility or single buyer; also, power could be sold directly to an end-user under a bilateral agreement, or to a power broker via a PPA, which is usually the case for larger hydro installations. Often, smaller facilities sell electricity under feed-in-tariff schemes, which guarantee a fixed price. Off-taker creditworthiness is crucial for project financial viability.
- **Contractors.** Construction and equipment suppliers are the primary suppliers to the SPV before the HPP power plant becomes fully operational.
- **Operating company.** If the SPV does not cover O&M, an agreement must be undertaken with another service provider for project operation and maintenance.
- **Insurance company.** Insures the project against investment risks such as construction delays, operation failures, or late payment from power purchaser or electricity administration. Insurance is necessary before project completion and during plant operation:
    - Insurance during pre-completion phase—covering construction risks, environmental and political risks,
    - Insurance during post-completion phase—covering O&M risks (operational failures), environmental, political, non-payment and transfer risks.

Risk mitigation actions for the project are based on sponsors, bank requirements, and managerial discretion.

15.2.3 Risks and mitigation measures

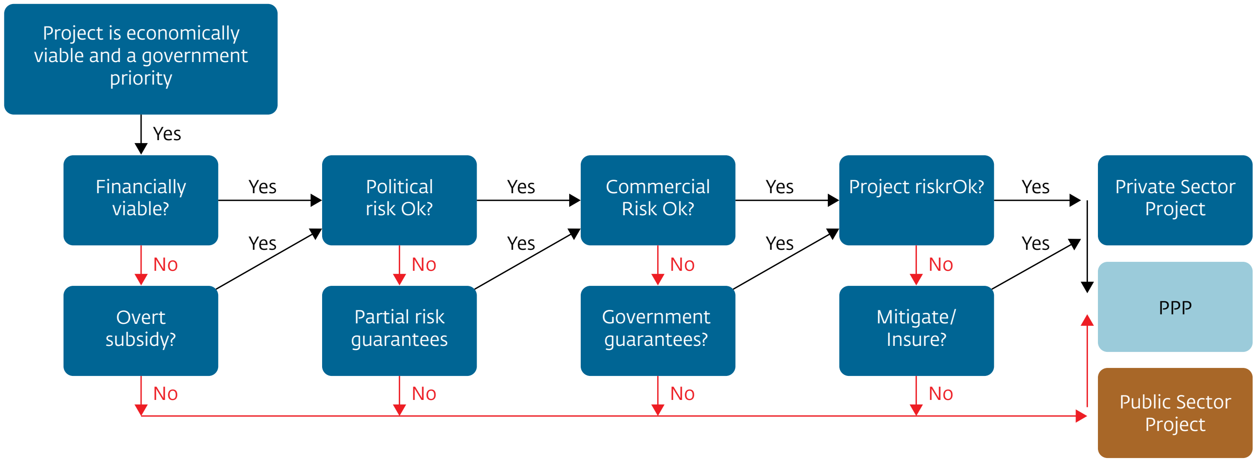
Risks can strongly influence hydropower project financing. Most project lenders are risk-averse and seek secure repayments; but equity investors accept higher risks for which they are entitled to higher returns.

Risks can reduce project attractiveness for some lenders; other lenders are willing to accept more risks for higher yields. But if the project risk profile is too high, project financing may not be feasible. Thus, a well-prepared financial analysis should include a detailed risk analysis.

Some risks could and should be mitigated to keep lender interest rates low. Mitigation measures vary depending on the risk, so financial modeling and sensitivity analysis should be undertaken to derive the effects of risks. The following are key risks from the perspective of project developers and lenders:

- **Hydrology**. Poses the highest risk for HPP development because it determines plant power generation and revenues. Reliable data are a prerequisite for sound project planning; this risk can be minimized through long-term time series of daily hydrological data and a sound methodology to determine expected water flow at the potential site. Nevertheless, uncertainties will exist about future discharges because they could deviate from historical values, due to climate change for example. This risk is out of the control of the developer, but can be simulated.
- **Permitting/licensing.** This is a complex process with high potential for delays and increased costs because it involves multiple agencies and approvals. Risk mitigation involves familiarity with specific requirements, early engagement with the relevant agencies and collaboration with experienced local partners or consultants; also, early engagement of the local community and affected stakeholders.
- **Payment default.** The off-taker (utility) may be unable to fulfill payment obligations. To mitigate this risk, an escrow account with a minimum holding could be established; also, the Government could issue a guarantee.
- **Local currency devaluation.** If the financial market is sufficiently developed, formal hedging is possible. In same cases, tariffs (e.g. Feed-in Tariffs) may be indexed to a foreign currency providing adequate protection. If these two options do not apply, the SPC must assume the foreign exchange risk.
- **Change in the regulatory framework:** If the tariff and off-take terms (e.g., obligation to take all electricity produced) are affected by a regulation supporting HPPs, it is possible that the government may change the regulation retroactively affecting signed PPAs. This is not common, but it has happened in recent years, mostly on wind and solar projects and it could happen in HPP projects. Potentially this risk can be covered, but in either case, the developer should assess the sustainability of the regulatory framework and the ability of the off-taker to pay.
- **Cost overruns and schedule delays.** As noted earlier, HPP projects are dominated by upfront civil works costs, which constitute 50 percent or more of total project costs (see Section 13.2.3.1). Because each HPP project is a one-off, exposure to external factors such as geology, natural hazards, or extreme weather, these costs are unpredictable and high-risk. Some of these risks can be controlled through comprehensive technical assessments; also, some risks could be shifted to the EPC.
- **Market dynamics.** Countries dominated by hydro generation may experience typical seasonal market challenges such as inadequate supply during the dry season and oversupply during the wet season. During dry months, a relatively low percentage of generated power is sold at premium prices when demand is high. During the wet season, prices are low and there is likely an oversupply of generated power, unless it can be exported. Consequently, the developer must consider the increased risks from future

Figure 15-3: Risks and project development



Source: Head 2006

additions to power generation, which could affect power supply market dynamics.

A detailed list of hydro development risks is found in Section 17.2. Potential risks influence how the project is financed. Figure 15-3 displays this notion graphically.

15.2.4 Financing sources and schemes

Selecting an appropriate HPP project financing scheme and sources of finance depends on project size, capital requirements, project financial viability, and project risks. For the largest projects, the public sector may be the only source of finance, however if capital requirements and risks are low, a corporate finance scheme might be appropriate. Typically, complex projects opt for project finance as outlined in Section 15.3.1.

Figure 15-4 below summarizes how project size relates to the choice of financing scheme and provides a matrix to select an appropriate scheme.

Figure 15-4 also implies that some hydro projects are too small for project finance and too risky for corporate finance, which could create a potential financing gap.

Common private sector financing models include the following:

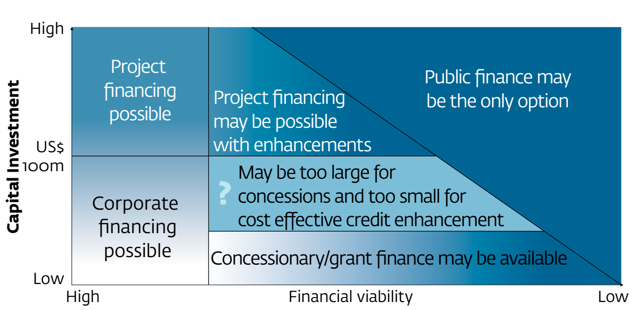
- **BOT—build-operate-transfer.** This is the preferred funding mechanism for small HPP and is applied extensively in infrastructure projects and public private partnerships (PPPs). In the BOT framework, a third party, such as public administration, delegates the task of designing, building infrastructure, financing and operating the plant for a fixed period (e.g., 20 years) to a private sector entity. During this period the private sector entity will collect all project-generated revenues, which should be adequate to cover the obligations to the lenders and provide a reasonable profit commensurate to the risks assumed. When the concession agreement ends, the facility is transferred to the public administration without further remuneration to the concessionaire.
- **BOO—build-own-operate.** Under this finance model the private company retains the facility and any residual project value because the physical life of the project coincides with the concession period. A BOO scheme involves very large investments and a long payback period.

Depending on the financing option, appropriate debt sources will be selected (Table 15-1).

Figure 15-5 summarizes sources of finance most likely to be applied under different financing schemes.

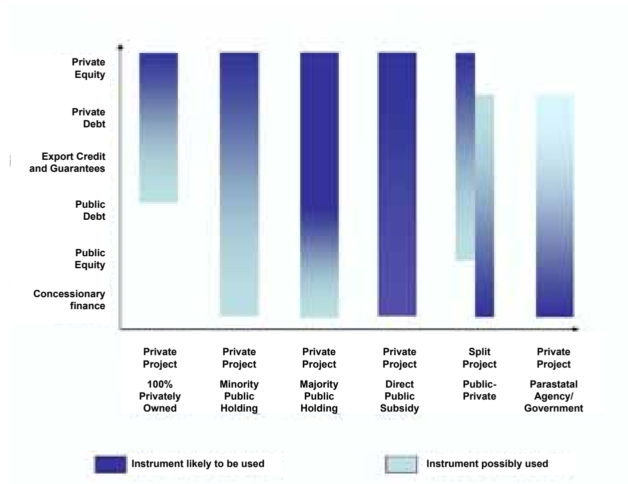
Financing terms, not only the interest rate but also the tenor, affect significantly the tariffs, as illustrated in Box 15-2.

Figure 15-4: Financing options in relation to project size



Source: Head 2006

Figure 15-5: Financing instruments for project structures



Source: Head 2006

Table 15-1: Sources of finance

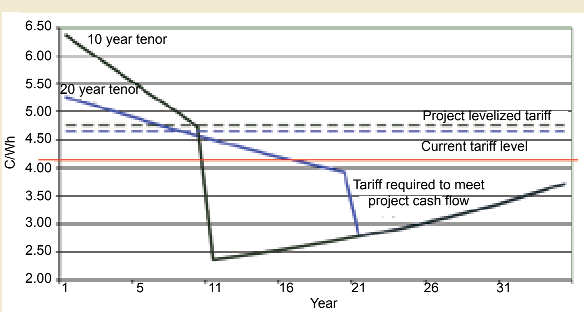
Types of Finance	Source	Interest	Tenor
Concessionary finance grants or soft loans	Bilateral sources or multilateral development agencies; carbon credits	Very low	Long-term
Public equity	Public investment (government-supported) Some public equity is indirectly funded through bilateral/ multilateral development banks	Dividends cans start low and increase over time	Indefinite
Public debt	Government loans, public bonds, or multilateral development banks	Low rates set by government or development banks	Medium to long-term with optional grace period
Export credit	Finance through Export Credit Agencies	Medium to high	Variable but commonly short- to medium-term
Private commercial debt	Private banks, commercial arm of development banks	High (may be lower with a guarantee)	Short- to medium-term (possibly extended with guarantees)
Private equity	Private sponsors, private investors, commercial arm of development banks	High dividends are expected as risk compensation	Depends on concession length

Box 15-2: Debt tenor and tariffs

Finance can significantly affect a hydropower project tariff, as is the case with many infrastructure projects. However, with hydropower the relationship between finance and tariff is magnified by the following hydropower characteristics:

- Technical lifespan of up to 60 years
- Debt repayment can be as short as 12 years
- Development costs are high and front-loaded

As a result, actual tariffs needed to service debt are likely to be much higher during initial project years. The graph below illustrates 10-year and 20-year debt tenors; resulting tariffs are compared to the levelized tariff (i.e., discounted average tariff).



Source: Plummer (2011)

The graph above shows that the longer the debt tenor, the closer the tariff will be to the levelized tariff. Therefore, hydropower investments should be seen as long-term investments and possibly long tenor debt should be sourced to keep tariffs at bay. The high tariffs that result from short tenor debt make hydro projects unattractive due to decreased economic viability.

15.3 Conclusion

Hydropower finance is complex due to the following characteristics:

- Long operating life
- High capital costs
- High construction risks
- Site-specific, each development is unique
- Environmental and social considerations
- External benefits and multipurpose benefits often not monetized by the project developer.
- Uncertain power generation due to variable hydrology

- HPP financing requires long-tenor, making it harder to attract private investment.
- Risks influence investor choices; high-risk projects are likely to be developed and financed by the public sector; low-risk projects attract private sector investors. Projects with risk mitigation measures can be developed and financed as a PPP.
- Risks and project development type influence debt and equity sources.

Overall financing scheme depends on project size and financial viability. Box 15-3 provides examples of HPP project finance.

Box 15-3: Financing hydropower: International experience

Theun Hinboun (120MW) Lao PDR
The first IPP concession project; initial concession period of 30 years and option for 10-year extension. Most of the electricity is taken off by Thailand. The project was financed with a debt-to-equity ratio of 55/45, primarily due to the Asian currency crisis; the equity share was financed through an ADB loan. Royalties of 5.0 percent are paid to the Ministry of Finance and dividends to the state. After the concession period the plant reverts to the government.

Allain-Duhangan (120MW) India
The project was privately developed by a local and foreign sponsor as a merchant plant without a long-term power off-take agreement. Most power was sold directly to industrial off-takers (eligible customers). The project was financed with a debt-to-equity ratio of 65/35; debt was provided by an IFC loan and local banks.

San Roque (345MW) Philippines
When public sector finance failed the project was successfully implemented under a PPP scheme. Under this split ownership project the dam was publicly financed through a soft loan; the power station was financed through a debt-to-equity ratio of 75/25. The debt was sourced through export credits, Japanese government loans and commercial loans. The generated power was taken-off by a utility, backed by sovereign guarantees.

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16

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Detailed geological mapping of a project site must be carried out to provide information on potential risk zones, etc. To complement geological mapping, further geotechnical and geophysical site investigations are carried out during project feasibility phase.

Annex 17

17.1 Comprehensive checklist for hydropower projects

Table 17-1: HPP project checklist

Information required	Initial Screening (Phase 1)	Screening (Phase 2)	Due Diligence (Phase 3)	Description
General Information				
Site selection	X	X	X	Already in the PFS (at Phase 2) information on project location and access must be provided, preferably with a location map. Also, the distance from project to grid system and feed-in point shall be addressed.
Access to site		X	X	
Connection to grid		X	X	
Key HPP parameters	X	X	X	Key project parameters shall be summarized in a table, including the following: Installed capacity • Annual energy generation • Design head • Design discharge • Number of units
Geology				
General geology of project area		X	X	General geological information of project area is provided in the PFS and FS. Further information on seismicity will be included in the FS and will be assessed in Phase 3. During the FS, detailed geological mapping of project site must be carried out to provide information on potential risk zones, etc. To complement geological mapping, further geotechnical and geophysical site investigations are carried out during project feasibility phase. The type of investigations, the laboratory test results and their impacts on the design are described in the FS.
Seismicity			X	
Geological mapping → Information on risk zones			X	
Geotechnical and geophysical investigations → design parameters as per results from laboratory tests			X	
Hydrology				
Catchment area (general description and key data)		X	X	The project area hydro-meteorological characteristics together with catchment area information (e.g., elevation, area, slope, etc.) shall be provided in the PFS and the FS. General hydrology information must be assessed in Phases 2 and 3. A detailed hydrological analysis is carried out in Phase 3 based on a detailed description in the FS report. This includes presenting the data basis (e.g., number of gauging stations, type of data, length of time covered by records)
Hydro-meteorological stations and data available (runoff, rainfall, temperature, etc.)			X	
Hydrological analysis: Flow available for power generation Flood discharges			X	

(continued)

Table 17-1: HPP project checklist *(continued)*

Information required	Initial Screening (Phase 1)	Screening (Phase 2)	Due Diligence (Phase 3)	Description
Environment and Social				
Environmental and social impact assessment prepared		X	X	During Phase 2, an assessment must be carried out to establish whether the project fulfills the environmental and social legal requirements. Typically this includes preparing an environmental and social impact assessment (ESIA); then based on the results, an environmental and social management plan (ESMP) is prepared. In general, environmental issues may have been briefly addressed in the Phase 2 based on PFS results, but usually are described in detail in the FS to thoroughly evaluate environmental risks and quantify necessary mitigation measures. In this connection, determining the minimum flow is crucial because flow is the key determinant of annual energy generation, which determines project viability.
Minimum flow			X	
Protected areas			X	
Power output and electricity generation				
Determination of installed capacity			X	Although expected power output and power generation are noted in the PFS (at Phase 2), determining installed capacity and calculating annual energy generation are carried out in detail in the FS (Phase 3). The computations are based on hydrological analysis results, i.e., flow available for power generation. In this connection, special attention is paid to the quality of the hydrological database (daily or monthly average flow data). Using monthly average flow data usually results in overestimating annual energy generation. The probability analysis for dry years should be included in the FS to assess the financial risk of low energy production.
Computation of annual power generation			X	
Probability analysis for dry years			X	
Layout and design of HPP				
Project concept and general layout	X	X	X	Project concept presentation and the general layout of the HPP scheme are part of project appraisals in Phases 2 and 3. The FS (Phase 3) provides detailed descriptions of all project structural components including detailed drawings (plan views, sections, etc.). Hydraulic computations must be presented in the FS to verify the dimensions of the hydraulic structures.
Detailed description of structural components, including hydraulic computations: dam, weir, diversion structure, intake waterways, powerhouse, tailrace			X	
Drawings—Project overview and general layout plan		X	X	
Drawings—Detailed drawings of all structures			X	
Electro-mechanical and hydro-mechanical equipment				
Selected turbine type		X	X	Detailed information on E&M equipment and hydraulic steel structures is usually part of FS and thus can be evaluated only in Phase 3. Turbine types are selected according to available head and selected design discharge.
Description of hydraulic steel structures			X	
Description of electrical equipment			X	
Transmission and grid connection				
General description of connection to the grid system		X	X	The general description of the grid connection is part of the PFS and FS. The FS then provides detailed information on all transmission system components to be assessed as part of due diligence (Phase 3).
Description of switchyard			X	
Description of transmission line and feed-in point			X	
Project implementation schedule				
Planned timeline for project implementation		X		A detailed implementation schedule must be prepared for the FS. The implementation schedule must consider not only construction time for the civil works, but also manufacturing, delivery and installation time for the E&M equipment. A preliminary schedule, to be prepared for the PPS will be the basis for assessment during Phase 2.
Detailed implementation schedule divided into civil works components, E&M equipment (manufacturing, delivery and installation), transmission line components, commissioning and testing			X	

(continued)

Table 17-1: HPP project checklist *(continued)*

Information required	Initial Screening (Phase 1)	Screening (Phase 2)	Due Diligence (Phase 3)	Description
CAPEX				
Preliminary cost estimate divided in main components: civil works, E&M equipment, transmission line	X	X		Generally, a preliminary cost estimate is given in Phase 2, which includes the cost relation of the main project components (i.e., civil works, E&M equipment and transmission system). During Phase 2, it is recommended to check that the list of cost items is complete and that the estimates are adequate. Detailed cost estimates are part of due diligence (Phase 3). Costs for civil works are usually based on the bill of quantities (BOQs) and unit costs of materials. These figures must be benchmarked to comparable costs for national civil works. The assessment must be undertaken by an independent engineer experienced in the local civil sector. For the E&M equipment and the transmission system, assessment of the CAPEX is based on supplier quotations. This should include a completeness check, i.e., not only the equipment but also delivery to the site, and implementation, including commissioning
Detailed cost estimates based on BOQ and/or quotations for engineering and design, civil works, E&M equipment,transmission line, environmental mitigation, project management and supervision			X	
OPEX				
Preliminary cost estimate divided into main components:concession and other fees, salaries, insurance, and maintenance	X	X		During Phase 2, rough estimates for main cost components should be checked. These include the following: • *Maintenance costs:* about 0.5% of CAPEX for civil structures; 2.0% for equipment. • *Salaries:* about 2 employees per plant, depending on size and number of plants and degree of automation. • *Insurance costs:* about 0.5% of CAPEX (civil works and equipment). • *Concession fee:* annual concession fee is usually 2% of revenues from generated electricity sales. In Phase 3 of the appraisal process, the focus shall be on the developer's operational concept, especially staff for plant O&M and maintenance procedures. Based on this, estimated staffing expenses and maintenance costs will be assessed.
Detailed cost estimate based on operational concept: concession and other fees, salaries, insurance costs, maintenance costs,other costs			X	

Source: FICHTNER

17.2 Risks associated with hydropower projects

Table 17-2: Risks of Hydropower Projects

Risks	Description	Mitigation
Political risks		
Political change	Due to local or national changes in government, policy, legislation, regulation, instability, or unrest	Enact special legislation, sovereign guarantees, political-risk guarantees
Corruption	Due to damage to project implementation or developer reputation caused by effects of corruption	Enact anti-corruption policy, vet contractors, insist on transparent practices, adopt third-party monitoring
Licensing	Due to shortcomings in administration or changes in the legal framework that might delay licensing process	Enact special legislation, sovereign guarantees, political risk guarantees
Transboundary issues	Upstream and downstream riparian rights and treaties, border security issues, etc.	Develop treaties, agreements, water management plans, benefit-sharing agreements, co-development, co-ownership
Economic and financial risks		
Cost escalation	Due to inflation, commodity prices, competition for resources, etc.	Enhance supervision, enhance investigation and design, adopt fixed-price EPC, hedge against price increases of inputs, transfer risk through bonds, contracts, insurance, etc.
Foreign exchange	Due to currency gap between costs and revenues	Transfer risk to contractor, hedging
Electricity market	Due to changes in tariffs, regulatory mechanism for setting prices, etc.	Seek long-term off-take agreement, hedging

(continued)

Table 17-2: Risks of Hydropower Projects *(continued)*

Risks	Description	Mitigation
Economic and Financial Risks *(continued)*		
Financing package	Due to financing instruments/tenure of available finance	Seek sovereign guarantees, refinance option, low debt interest rate, longer repayment periods
Performance of contractors / schedule delays	Delays due to inadequate scheduling	Prequalify contractors, contract terms and conditions, transfer risk through bonds and insurance, warranties and guarantees, etc.
Technical Risks		
Hydrological	Due to lower or higher-than-expected water flows, floods, unusual seasonal variations	Thorough hydrology analysis, contingency margin for output, detailed investigation during feasibility and design phases
Geotechnical seismic	Due to geological activity structural problems arise	Detailed analysis, site-specific design
Electro-mechanical equipment performance	Due to underperformance as per project specifications	Supervision, inspection, quality assurance, reliability tests, guarantees and warranties
Construction	Due to construction delays	Supervision, inspection, quality assurance, reliability tests, guarantees and warranties
Operation and maintenance	Due to underperformance of O&M	Detailed O&M contracts, guarantees and warranties
Social Risks		
Land and water use conflicts	Due to conflicts with local water users or downstream riparian, water use	Formal agreement with stakeholders, modify design
Resettlement and social unrest	Due to resettlement, local employment and compensation	Formal agreement with stakeholders, modify design
Public health and safety risks	Due to threats to public safety or health during all project phases	Safety management plan, formal agreement with stakeholders, modify project
International objection on social, environmental or cultural grounds		Develop and carry out strategic communications strategy, modify project
Cultural heritage issues	Preservation of historically significant sites and artifacts	Design pre-project activities to investigate, preserve, or modify project
Environmental Risks		
Water quality		Modify project, compensate for impacts
Sedimentation		Modify project
Upstream/downstream flow regime		Modify project, compensate for impacts
Wetlands protection		Modify project, compensate for impacts
Biodiversity		Modify project, compensate for impacts, pest management
Fish habitat		Modify project, compensate for impacts

Acronyms

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ADB	Asian Development Bank
AVR	Automatic Voltage Regulator
B/C	Benefit/Cost ratio
BOO	Build-Operate-Own
BOT	Build-Operate-Transfer
BREP	Balkan Renewable Energy Program
CAPEX	Capital Expenses
DSCR	Debt-Service Coverage Ratio
E&M	Electrical and Mechanical
E&S	Environmental and Social
EIA	U.S. Energy Information Administration
EP	Equator Principles
EPC	Engineering, Procurement and Construction
ESIA	Environmental and Social Impact Assessment
ESMP	Environmental and Social Management Plan
ESMS	Environmental and Social Management System
FDC	Flow Duration Curve
FIDIC	Fédération Internationale des Ingénieurs-Conseils
FIRR	Financial Internal Rate of Return
FiT	Feed-in Tariffs
FS	Feasibility Study
GIIP	Good International Industry Practice
GIS	Geographic Information System
GRP	Glass-fiber-reinforced Plastic
GW	Gigawatts
H	Head
HPP	Hydro Power Plant
HVAC	High-Voltage Alternating Current
ICOLD	International Commission on Large Dams
IEA	International Energy Agency
IFC	International Finance Corporation
IHA	International Hydropower Association
IP	Indigenous Peoples
IR	Insulation Resistance
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
kW	Kilowatt
LCOE	Levelized Cost of Electricity
LUC	Levelized Unit Costs
MFWL	Maximum Flood Water Level
NPV	Net Present value
O&M	Operation & Maintenance
OPEX	Operating Expenses
PFS	Pre-Feasibility Study
PID	Process & Instrumentation Diagram
PM	Preventive Maintenance
PMF	Probable Maximum Flood
PPA	Power Purchase Agreement
PPP	Public-Private-Partnership
SHPP	Small Hydro Power Plant
SPV	Special Purpose Vehicle
TBM	Tunnel Boring Machines
TPC	Total Plant Costs
TWh	Terawatt-hours
USACE	United States Army Corps of Engineers
USGS	US Geological Survey
WACC	Weighted Average Cost of Capital

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