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PBL Netherlands Environmental
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Integration of hydropower in the IMAGE/TIMER model

Steps toward endogenous modelling of global hydropower by
construction of regional cost supply curves

Master thesis

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Preface

I hereby present my master thesis written at *Utrecht University (UU)* and during an internship at the *PBL Netherlands Environmental Assessment Agency* (in Dutch: *Planbureau voor de Leefomgeving*). The subject of this thesis is the integration of hydropower in the *Targets IMAGE Energy Regional* model (TIMER), the energy submodel of the *Integrated Model to Assess the Global Environment* (IMAGE), a global integrated assessment modelling framework developed by PBL. The purpose of TIMER is to simulate the global energy system and to integrate its output within the IMAGE framework. TIMER can also be used as a standalone model. Gaining more knowledge on energy in its entire context, that is from a societal, technological, economic and environmental perspective is an important element of this thesis and the master Energy Science. Integrated Assessment Models such as IMAGE are tools to improve the understanding between the linkages. Historical trends and projections on the development of fossil energy and renewable energy are key to give directions to society, scientists, policy and decision makers. This work contributes to a renewed representation of hydropower in TIMER by constructing regional cost supply curves.

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Summary

In the electricity sector, hydropower or “hydro-electricity” is currently the largest renewable energy source, with a global capacity of about 1 TW in 2013 and providing 85% of global electricity from renewable sources. However, despite the importance of the resource many energy models pay much less attention to hydropower than to other renewables. In the energy model TIMER used at PBL Netherlands Environmental Assessment Agency as part of the IMAGE framework, hydropower is modelled as an energy technology that has a prescribed capacity and does not compete on a cost base with other energy technologies to gain market share. This is done by calculating a desired fraction of the ultimate exploitable hydropower potential. The current representation in TIMER of hydropower, however, has severe limitations. Renewable energy is becoming increasingly important, given the expected increase in overall energy demand, the depletion of conventional fossil resources and climate change. Hydropower could therefore become more attractive than historically.

This work contributes to a renewed representation of hydropower in TIMER by means of regional cost supply curves. The costs supply curves are determined in a sequence of process steps. First, the theoretical potential for hydropower is calculation using discharge data from hydrological models and elevation data from DEMs. Next, geographical constraints and technical limits are added. After this, the LCOE of hydropower is calculated. Finally, the technical potential per region and LCOE are aggregated into cost supply curves.

The cost supply curves seem reasonable at representing large regions since lots of hydropower production points lay on realistic positions on the costs supply curves. Some regional technical potentials are overestimated and some underestimated compared to survey data. The reasons for this are different per region. Some correction factors were introduced to improve the representation of smaller IMAGE regions such as Japan, Central America and Europe.

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1. Introduction

Climate change, conventional fossil fuel depletion and an expected growing energy demand are important sustainability related issues that we as humans need to deal with in the 21st century. In this context, renewable energy is becoming increasingly more important (IPCC SRREN 2012). In the electricity sector, hydropower or “hydro-electricity” is currently the largest renewable energy source, with a global capacity of about 1 TW in 2013 (IJHD 2013) and providing 85% of global electricity from renewable sources (GEA 2012; IEA 2012). Considering global electricity generation, hydropower accounts for 16% (GEA 2012; IEA 2012) while other renewables account for 2.6% of global annual generation (GEA 2012; IEA 2013). In terms of primary energy, hydropower provided 2.3% of global annual total primary energy supply (TPES) in 2013 (IEA 2013). However, despite the importance of the resource many energy models pay much less attention to hydropower than to other renewables. In the energy model TIMER, for instance, used at PBL Netherlands Environmental Assessment Agency as part of the IMAGE framework, hydropower is modelled as an energy technology that has a prescribed capacity and does not compete on a cost base with other energy technologies to gain market share. Country survey data on hydropower potentials from the World Energy Council (2001) is used to attain the installed capacity per world region for use in the scenarios (WEC 2001). This is

done by calculating a desired fraction of the ultimate exploitable hydropower potential. More about the current representation of hydropower in TIMER is given in Appendix 1. The main reason to model hydropower exogenously was that hydropower projects are most often multipurpose projects whereby electricity production is not the main reason to build a dam. In case of multipurpose projects, the investments in hydropower dams are thus not necessarily driven by the need to generate electricity. The current representation in TIMER of hydropower, however, has severe limitations. Renewable energy is becoming increasingly important, given the expected increase in overall energy demand, the depletion of conventional fossil resources and climate change. Hydropower could therefore become more attractive than historically. In addition, hydropower could play an important supporting role in the penetration of intermittent renewables such as wind and solar (IRENA 2012). Also, Pumped hydro storage (PHS) could become important for the penetration of wind and solar in the future energy system (IRENA 2012).

In this research it's hoped to obtain more insight on the potential role of hydropower in the global energy system by taking a look at the technical exploitable hydropower potential on a world regional level. More specifically, the aim of the thesis is to answer the following research question:

What is the regional potential for hydropower and at what cost levels can that potential be exploited?

Determination of the technical exploitable potential per region for the development of hydropower:

- First the theoretical potential for hydropower is calculated on a medium level of aggregation. In subsequent order the geographical, technical and economic potential are deduced from this. Definitions of different types of potentials are given in box 1. Each of these potentials reduces the theoretical potential based on one or more constraints as can be read about in the methodology. Hydropower is not modelled in any existing global integrated assessment model using this approach.

The construction of regional cost-supply curves:

- By estimating the production costs of hydropower (in \$/kWh) and combining this with the technical potential, regional cost-supply curves are constructed for inclusion in TIMER.

The outline of this thesis is as follows. First, a theoretical background is given on hydropower and the TIMER model. Then the methodology is described to construct cost supply curves. The next chapters look into the theoretical, geographical, technical and economic potential. Next, a discussion is given and conclusions are drawn. Suggestions for further research are given at the end.

Box 1: Types of Potentials

In determining the potential of (renewable) energy sources, geographical, technical and economic aspects play all different roles. Similar to Hoogwijk (2004), the following types of potentials are defined (Hoogwijk 2004).

- The **theoretical** potential is the theoretical limit of the primary energy source. For hydropower resources this is all energy associated with movements of surface water. In other words, all gravitational potential energy associated with every particle of water moving from where it falls on the surface down to sea level and captured at 100% efficiency.
- The **geographical** potential is the theoretical potential reduced by the energy generated at areas that are considered available and suitable for production.
- The **technical** potential is the geographical potential that can be generated within the limits of existing technology. Technological efficiency and resource availability both play important roles in determining the technical potential.
- The **economic** potential is the total amount of technical potential derived at cost levels that are competitive with alternative energy sources.
- The **implementation** potential is the total amount of the technical potential that is implemented in the energy system. Subsidies and other policy incentives can increase the implementation potential, but social barriers, for instance the displacement of people off hydropower sites can reduce the implementation potential. The implementation potential can be both higher and lower than the economic potential, but can never exceed the technical potential.

2. Research context

2.1 The role of Hydropower

The global electricity generation trend by source is depicted in Figure 1. The figure shows that hydropower generation is still increasing although relatively slowly compared to for instance coal, gas, solar, wind and tidal energy. There was a global annual growth rate of 2.3% in hydropower generation between 1990 and 2011 (IEA 2013). In OECD countries, the annual growth rate of hydropower between 1990 and 2012 was even lower, 0.7%, possibly indicating that hydropower is slowly approaching its maximum potential capacity (IEA, 2013).

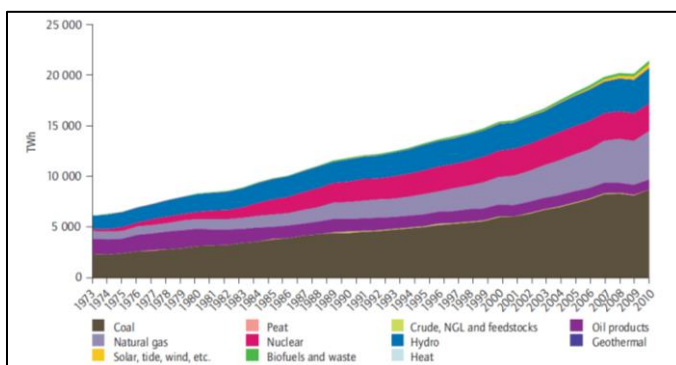


Figure 1: Global electricity generation by source (1973-2010) (IEA 2012)

Outside OECD countries, there still remains a significant amount of unexploited technical and economic feasible potential when compared to actual generation, as can be observed from the figures of the International Journal of Hydropower and Dams (IJHD) in Table 1 (IJHD 2013). The International Journal of Hydropower and Dams is an annual published international journal for the hydropower industry providing country survey data on hydro potentials, capacity and generation (IJHD 2013). It can be observed in table 1 that all continents have technical and economical potentials several hundreds of GWhrs higher than current generation. Europe’s generation is relatively closest to the technical feasible potential. With an estimated global economic feasible potential of 9.4 million GWh year⁻¹ and a 3.7 million GWh year⁻¹ generation in 2011, it appears that there is still a significant economic feasible potential left. According to the IJHD, the largest planned expansions in hydropower capacity are expected in Asia, followed by South America and Africa.

Table 1: Hydropower figures for 2013 and generation in the year 2011 (IJHD 2013)

	Gross theoretical hydropower potential (GWh/yr)	Technical potential (GWh/yr)	Economic potential (GWh/yr)	Installed capacity (MW)	Hydropower generation in 2011 or most recent/average (GWh/yr)	Hydro capacity under construction (MW)	Planned hydro capacity (MW)
Africa	4,426,000	1,581,000	994,000	26,000	115,000	20,000	50,000-125,000
Asia (incl. Russia, Turkey)	19,717,000	8,152,000	4,742,000	470,000	1,593,000	158,000	283,000-448,000
Australia/Oceania	657,000	185,000	89,000	13,000	42,000	120	900-2700
Europe (excl. Russia, Turkey)	3,129,000	1,205,000	847,000	184,000	532,000	9,200	25,000-26,000
North and central America	7,600,000	1,886,000	1,055,000	172,000	681,000	7,600	27,000-53,000
South America	7,893,000	2,807,000	1,677,000	145,000	707,000	29,000	73,000-83,000
World total	43,423,000	15,816,000	9,404,000	1,011,000	3,672,000	224,000	458,000-736,000

2.2 Types of hydropower plants

Hydroelectricity is generated by converting the gravitational energy of water flowing from higher to lower elevations. Hydropower plants vary in size and type of plant, size and type of turbine/generator (see Appendix 2), the height of the water fall (“hydraulic head”) and their main function (electricity generation, water storage or multi-purpose). Most often, the design of a hydro power plant is totally site specific, meaning that it has been adjusted to local circumstances (IEA 2012). Nevertheless, it is possible to define a general classification for hydropower plants based on

the way in which they operate. A number of publications discern between the following main categories of hydropower plants (IEA 2012; IPCC SRREN 2012; IRENA 2012):

1. Run-of-river (RoR) hydropower plant
2. Reservoir and dam (storage) hydropower plant
3. Pumped hydro storage (PHS) plant
4. Cascading system (a combination of a reservoir and RoR hydropower)

1. Run-of-river (RoR) hydropower plant

Run-of-river hydropower plants extract the energy from the available flow of water in the river. This extraction can happen along the course of the river itself *or* in a diversion scheme, in which water is channeled from a river, lake or dammed reservoir to a remote powerhouse containing the turbine and generator (IEA 2010b; Monk et al. 2009). The powerhouse is connected to a transmission system to the grid. A schematic picture of a RoR hydropower plant with diversion scheme is shown in Figure 2. For RoR hydropower plants, the water flow is mostly natural driven, but it might also be controlled by a reservoir upstream. Without upstream reservoir, the electricity generation is dependent on runoff and shows daily, monthly, seasonal and yearly variation (IPCC SRREN 2012). This might easily lead to load demand mismatches (IEA 2012). To improve meeting the demand, a more flexible supply side can be achieved by applying short term storage also called *pondage*. This involves filling up a small reservoir (*forebay*) with water in a diversion scheme (IEA 2012). Excesses of water can be released through *spillways*.

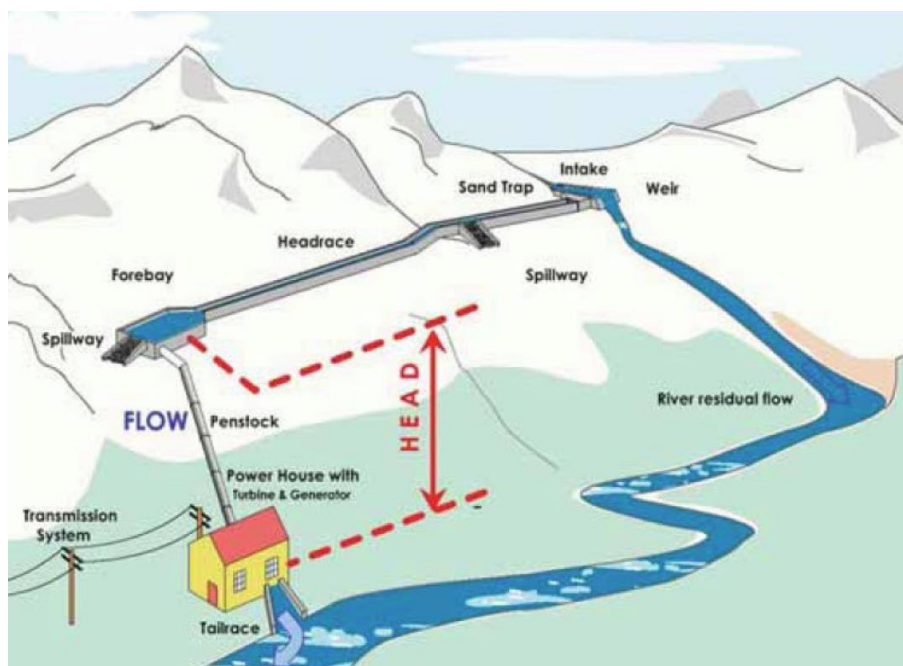


Figure 2: Schematic picture of a run-of-river hydropower plant (Green for Growth Fund & MACS Energy and Water 2012)

2. Reservoir and dam hydropower plant

Reservoir and dam hydropower plants store water in a reservoir, often in an artificial lake behind a dam. This water can be released on demand through sluice gates of the dam. It then flows through a *pipe* called penstock and thereafter it drives a turbine to produce electricity (see Figure 3). Using a

reservoir is beneficial, because it provides the flexibility to generate electricity on demand and reduces the dependency on natural water inflows. Large reservoirs can store water for months or even years of average inflows (IEA 2012). In this way, a lot of energy can be stored. In case of a (large) dam project, a reservoir most often has multiple purposes, such as providing drinking water, irrigation, flood and drought control, navigation¹ and energy supply (IPCC SRREN 2012). Even though electricity generation is often not the main purpose of a dam, it's still worthwhile to investigate the role of hydropower generation in the context of climate change. The exact services of reservoirs depend on the local conditions and needs. Most of the reservoirs are artificially created by building a dam to control the natural river flow. In some situations, natural lakes can also function as reservoirs (IEA 2012). Generally, reservoir and dam plants are larger in size than run-of-river plants. If the capacity of the plant is small compared to the river potential and if the reservoir size is sufficient, the plant might be used as base load the whole year. On the other hand, a larger plant would exhaust the potential more rapidly and the generation would then (preferably) only take place during peak hours (IEA 2012).

A specific benefit of hydropower dams is that energy is storable in the form of a reservoir and the output is controllable due to the controllability of the turbine. This flexibility implies that hydropower can be utilised to meet peak electricity demands as well as to balance electricity systems that have large quantities of intermittent electricity, such as wind or solar (IPCC SRREN 2012). Without means to store power, the intermittency of wind and solar power imply that 1) other capacity needs to act as back-up and 2) electricity needs to be curtailed if supply exceeds demand. One way to provide back-up capacity and to lower curtailment is to use hydropower both as back-up capacity and to increase the energy storage capacity by using reservoirs. Because of these grid services that hydropower offers, it could play a supporting role in the penetration of wind and solar power.

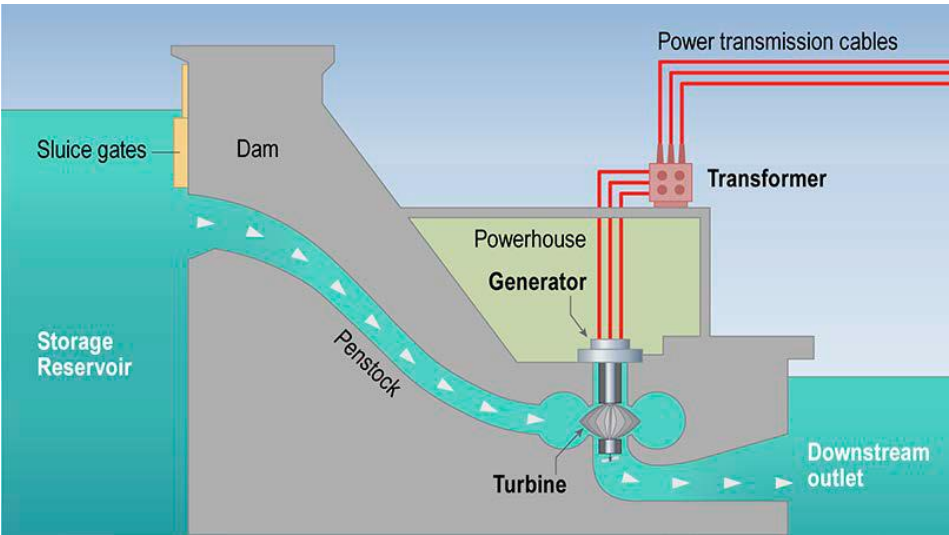


Figure 3: Cross section of a large hydropower plant based on a dam (Hall et al. 2012).

3. Pumped hydro storage (PHS) plant

Pumped hydro storage is another technique to store energy for reservoir hydropower plants. For pumped hydro storage, two reservoirs are required at different altitudes. In off peak hours, when

¹ Maintaining artificially high water levels in order to make it possible for ships to navigate (travel) from one place to another.

supply exceeds demand and electricity prices are low, electricity from the grid is utilized to drive an electric pump to pump the water in the lower reservoir to the higher reservoir (Figure 4). The water in the higher reservoir is stored and can be released for power production during peak hours when prices are higher (IEA 2012). Since electricity the electricity network itself has very limited storage abilities, large fluctuations in the electricity price occur during the day. PHS plants can use these fluctuations in electricity prices to earn cash, by simply storing energy by pumping when prices are low and by producing electricity if prices are high (EPRI 2013). In this way PHS production can be utilised to shave peak electricity prices down. PHS returns electricity to the grid with a roundtrip efficiency of 70-85%. Therefore PHS is a net consumer of electricity. Nevertheless, the application of PHS leads to storage and grid services and PHS is currently about 99% of on-grid storage for electricity (Guardiola and Rastler 2012).

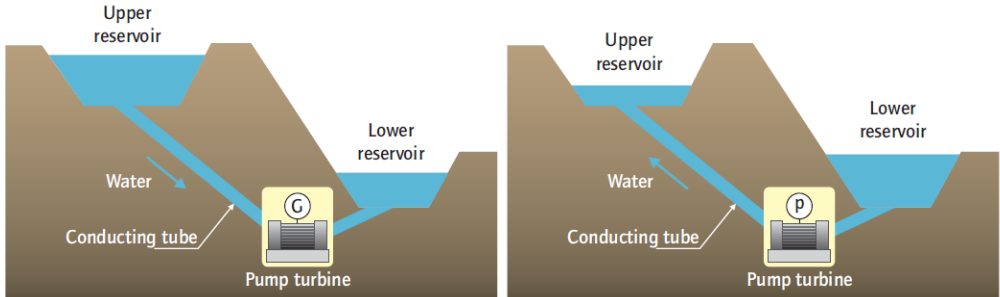


Figure 4: Cross section of a pumped storage hydropower plant (IEA 2012).

4. Cascading system (a combination of a reservoir and RoR hydropower)

The energy output of a RoR hydropower plant could be regulated by an upstream reservoir as is the case in cascading hydropower schemes (Figure 5). A large reservoir in the upper catchment generally regulates the outflows for several RoR or smaller reservoir hydropower plants (HPP) downstream. This likely increases the annual energy generation potential of the downstream sites, and enhances the value of the upper reservoir’s storage function (IEA 2012).

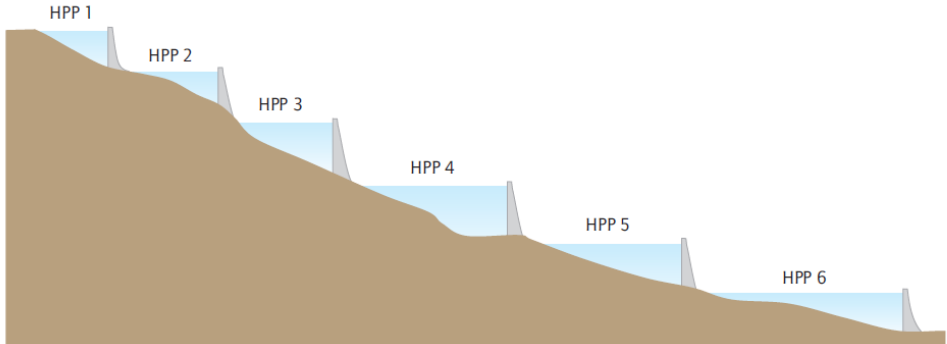


Figure 5: Cross section of a cascading hydropower scheme (IEA 2012).

2.3 Classification of hydropower

Hydropower plants can be classified into small or large installations based on their capacity, but there is no widely accepted classification system (IEA 2012). The IEA hydropower implementing agreement uses a classification for hydropower plants as shown in Table 2. Medium to large hydropower plants have capacities of more than 100MW and are used for both peak and base load

generation. They usually consist of a dam and reservoir. Smaller hydropower is typically run-of-river hydropower and is used for base load generation.

Sometimes, the term *small hydro* is used differently in other countries, but in general < 10MW is used as definition. Within the World Small Hydropower Development Report 2013 small hydropower is also defined as all plants with a capacity of up to 10 MW (WSHPDR 2013). The installed small hydropower capacity (up to 10 MW) is estimated at 75 GW in 2011/2012 (WSHPDR 2013). The global large hydropower capacity is then approximately: 1011GW (total global capacity, see Table 1) - 75GW = 931GW and therefore accounts for the major share of hydropower capacity.

Table 2: Classification of hydropower (based on IEA hydropower implementing agreement) (IEA 2010b)

	Category	Capacity	Storage type	Power use (load)	Typical specific investment costs (Million US\$/MW)
1	small	< 10 MW	run-of-river	Base load	2 - 4
2	medium	10-100 MW	run-of-river	Base load	2 - 3
3	medium	100-300 MW	dam and reservoir	Peak and base	2 - 3
4	large	> 300 MW	dam and reservoir	Peak and base	< 2

2.4 The IMAGE framework and the TIMER model

The IMAGE framework is an integrated assessment model (IAM) developed by PBL Netherlands Environmental Assessment Agency. The IMAGE framework has been developed to gain more insight and understanding on the complex relations between the global environmental system and human activities (Stehfest et al. 2012). The IMAGE model consists of different sub-models which are integrated into one framework as shown in Figure 6. IMAGE consists of a social economic system, an earth system and an impact system. The economy, population, technology and policy are used as scenario drivers to induce changes in the socio economic system, for instance more demand for livestock and more energy demand. After the changes in the socio economic system, the earth system responds in order to fulfil the new demand. Lastly, the impact of changes in the earth system is simulated in the impact system. The IMAGE framework is used for projections on impacts for agriculture, climate change, biodiversity, water use and more (Stehfest et al. 2012).

Figure 7 shows the world regions of IMAGE. The regions are modelled separately, meaning that regional model output can be obtained from the IMAGE model.

Results of the IMAGE model are used in several global studies such as the IPCC Special Report on Emissions Scenarios and the Millennium Ecosystem Assessment. It is also used for the fourth Assessment Report of the IPCC (Stehfest et al. 2012).

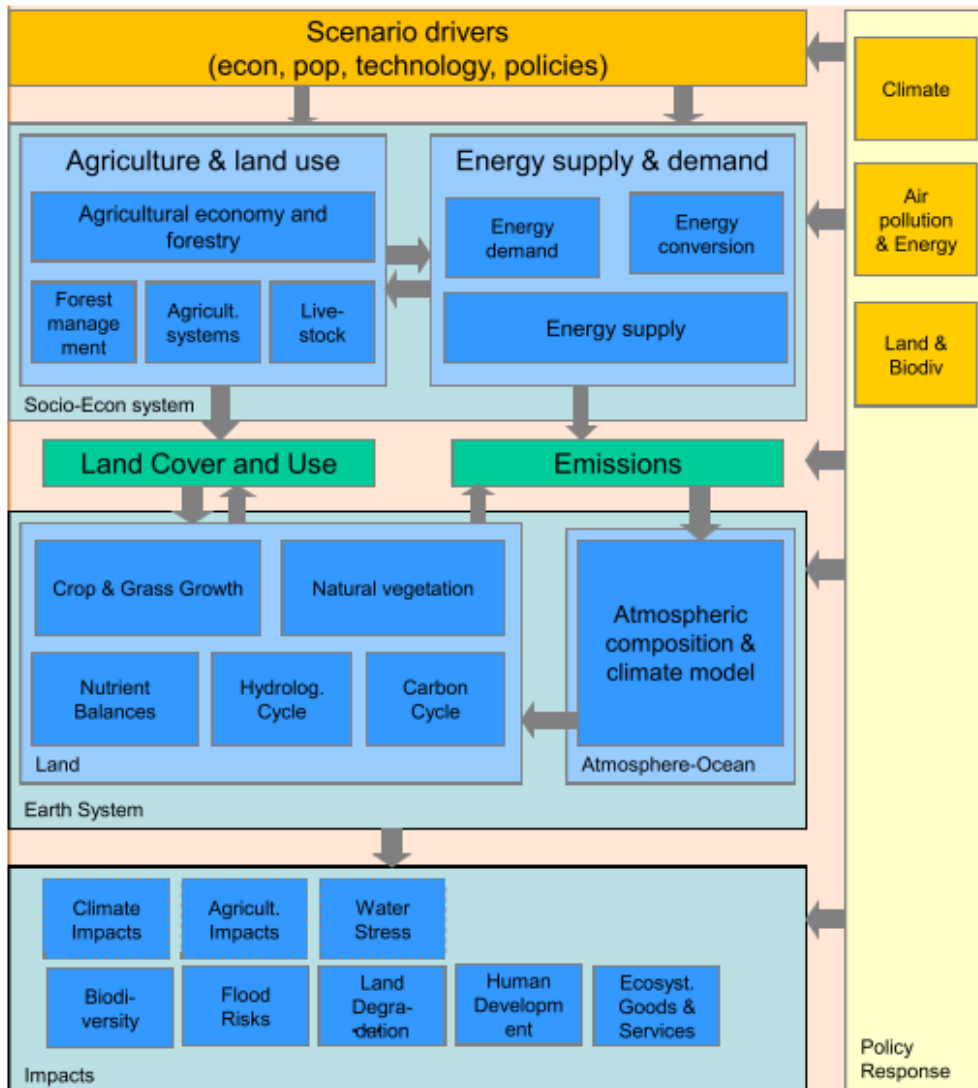


Figure 6: Overview of the framework of IMAGE 3.0 (Stehfest et al. 2012).

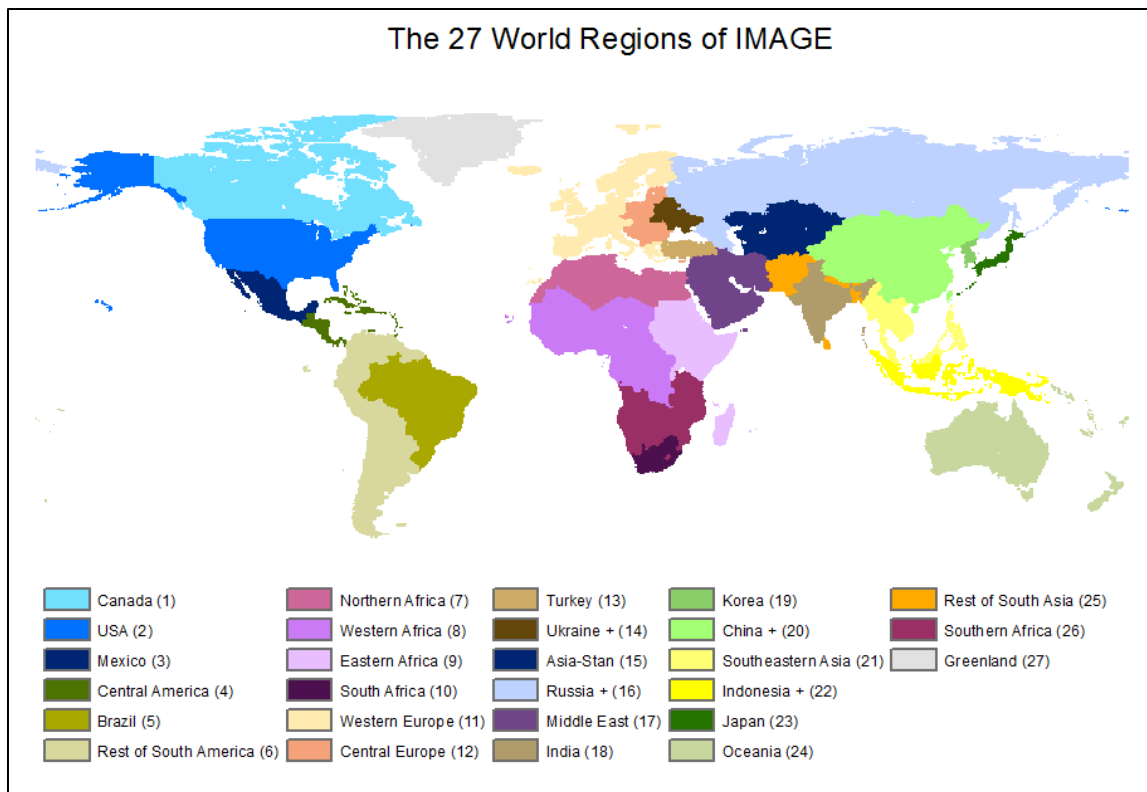


Figure 7: IMAGE 3.0 regional breakdown (PBL 2014).

The IMAGE model consists of several submodels, one of which is the energy submodel TIMER (The IMage Energy Regional model). The aim of TIMER is to describe long-term development pathways of energy technologies. TIMER is a bottom up simulation model focussing on several dynamic relationships within the energy system, for example inertia, learning-by-doing, depletion and trade among different regions (Van Vuuren 2007). TIMER uses regional energy intensities and population to calculate the useful energy demand. Then the final energy demand is calculated. It then calculates on a cost base which shares of primary energy will be supplied by each energy technology. An overview of the different components of TIMER is given in Figure 8. TIMER consists of a demand module, an energy conversion module and a supply module. The electric power generation (EPG) module of TIMER is the most important source of anthropogenic greenhouse emissions and is covered in this research. Considering renewable energy, solar, onshore wind, offshore wind, concentrated solar power (CSP), hydropower and biomass energy are already included in TIMER.

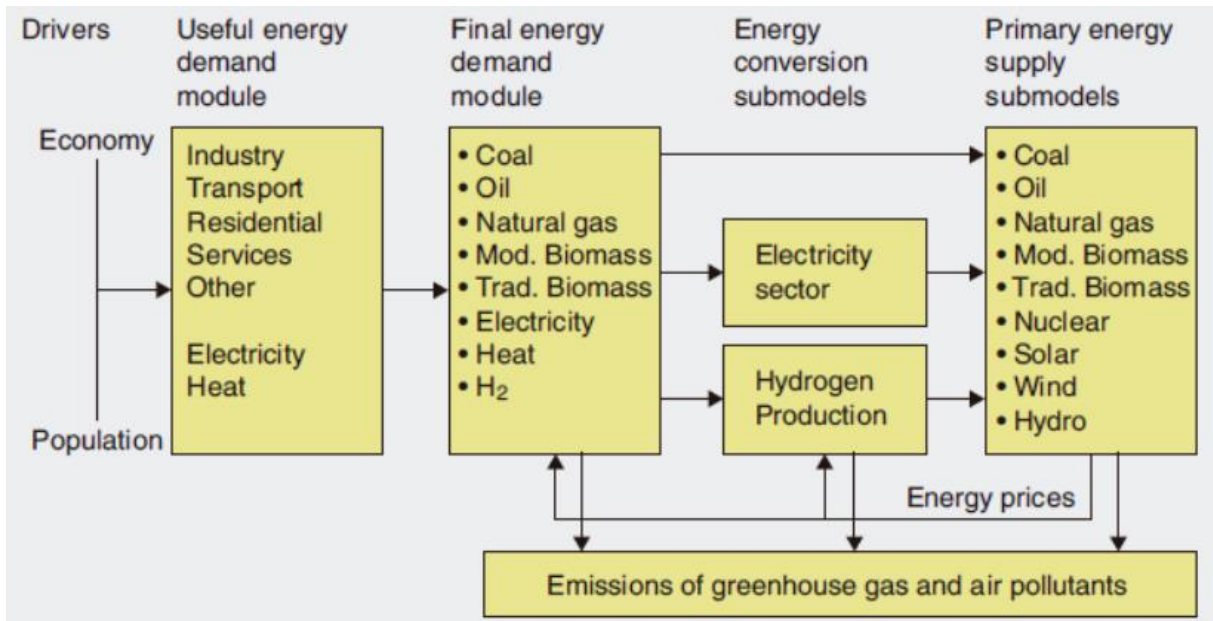


Figure 8: Overview of the TIMER model (Van Vuuren 2007)

2.5 The TIMER EPG module

The TIMER model consists of an Electric Power Generation (EPG) module as depicted in Figure 9. In TIMER EPG, technologies gain market share based on their levelized costs of energy (*LCOE*). The *LCOE* is the price at which electricity must be produced from a specific source to break even over the lifetime of the project (IEA & NEA 2010). It is an economic assessment of the cost of the energy-generating system which includes all the costs over the lifetime: initial investment, operations and maintenance, cost of fuel and cost of capital. This makes the *LCOE* useful in comparing the costs of generation from different energy sources. The *LCOE* is calculated with (IEA & NEA 2010):

$$Price_{elec} = LCOE = \frac{\sum_t \frac{I_t + O \& M_t + Fuel_t + Carbon_t + Decommissioning_t}{(1+r)^t}}{\sum_t \frac{Electricity_t}{(1+r)^t}} \quad (2.1)$$

With,

- $Price_{elec}$: the electricity price
- I_t : investment costs in year t
- $O \& M_t$: operation and maintenance costs in year t
- $Fuel_t$: fuel costs in year t
- $Carbon_t$: carbon costs in year t
- $Decommissioning_t$: decommissioning costs in year t

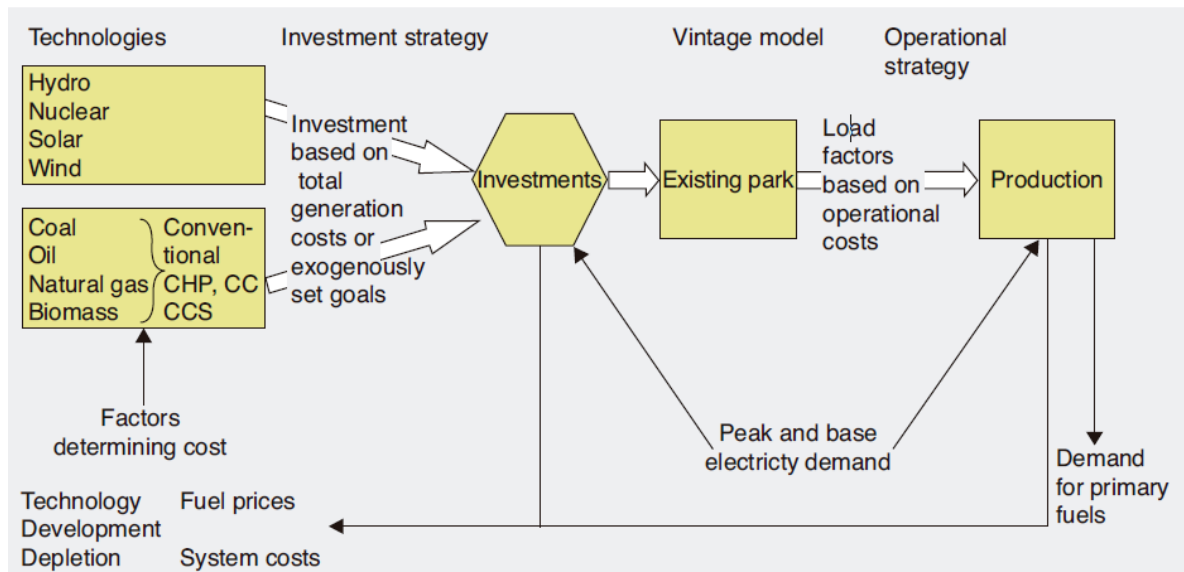


Figure 9: Schematic overview of the Electric Power Generation model in TIMER (Van Vuuren 2007).

TIMER simulates energy market dynamics using a substitution effect. Substitution of energy technologies happens in TIMER based on differences in the *LCOE*. This substitution effect of energy technologies is simulated using a multinomial logit function (Van Vuuren 2007):

$$IMS_i = \frac{\exp(-\lambda c_i)}{\sum_j \exp(-\lambda c_j)} \quad (2.2)$$

With,

- IMS_i : the indicated market share of technology i as a fraction of total newly installed capacity
- c_i : the *LCOE* for technology i .
- λ_i : the logit parameter, which indicates the sensitivity of the market to price differences.

The lower the *LCOE* of an energy technology, the more investments will be done and the more market share a technology achieves (except in case when investments are driven by exogenously set goals as indicated in Figure 9).

There are two major factors influencing the *LCOE* in TIMER. These are:

1. Depletion
2. Technological learning

2.5.1 Depletion

Depletion is an effect that describes the cost increase when more potential of an energy technology gets exploited (Van Vuuren 2007). Whenever more potential gets exploited the cost of further expansion increase as it is assumed, by economic rational behaviour, that the cheapest locations are used first. The depletion effects can be visualized in a depletion curve or cost supply curve. A cost supply curve is a graph showing which amount of cumulative capacity is installed (or which amount of energy is generated) at a certain costs level. Cost can either be expressed as specific investment

costs (unit: $\$/kW$) or as the $LCOE$ (unit: $\$/kWh$). An example of a cost supply curve is shown in Figure 10. When more capacity is installed, the costs increase as the locations of lowest costs are used first. By using regional cost supply curves, the representation of hydropower in TIMER can be improved compared to the current exogenous representation. This is, because market dynamics are introduced which are leading to substitution effects in equation 2.2. In order to model hydropower using cost supply curves in TIMER, an estimate is needed for the cost to install (new) hydropower capacity. This research focusses on developing cost supply curves for hydropower for each of the 26 world regions (excluding Greenland).

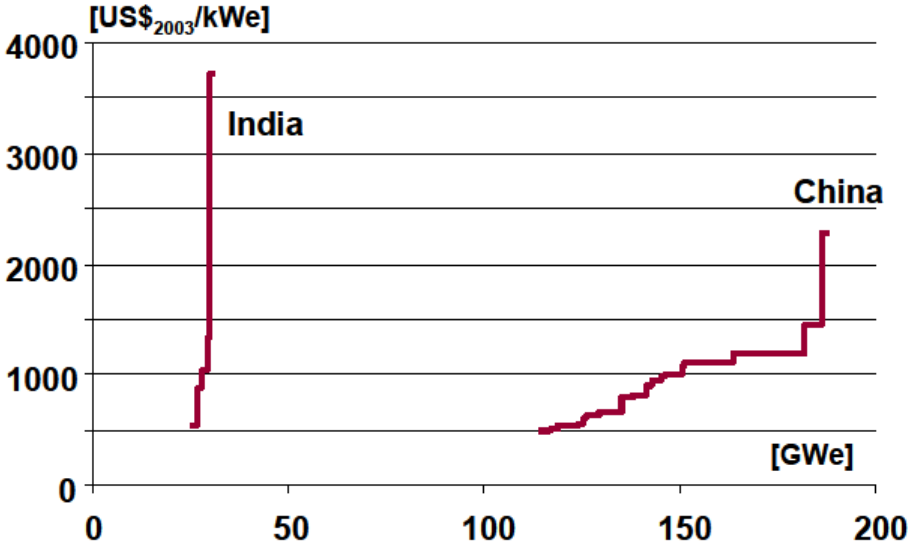


Figure 10: Example of a cost supply curve/depletion curve for hydropower in India and China (Lako et al. 2003).

The $LCOE$ for hydropower is relatively low compared to electricity from other sources (IEA & NEA 2010; IRENA 2013). The low $LCOE$ are the main reason that hydropower plants are often used as base load. Though, hydropower may also be used for peak demand, because of fast start up times.

2.5.2 Technological learning

Aside from depletion effects, learning effects are also causing changes in the $LCOE$. A learning curve shows the relation between the amount of experience made and the learning effects (Hoefnagels et al. 2011). Experience is expressed as the amount of installed capacity. The learning effect is expressed as a factor of the capital costs relative to a base year. A learning curve can be graphically plotted as cumulative installed capacity (Cum) versus the costs (C) per unit of capacity. It can be fitted with the function:

$$C = C_0 Cum^b \tag{2.3}$$

whereby C are the costs, C_0 are the costs of the first unit installed, Cum is the cumulative installed capacity and b is a constant called the learning parameter (Hoefnagels et al. 2011). For each doubling in capacity, the associated cost ratio is called the learning rate, i.e. $LR = 1 - 2^{-b}$. The progress ratio is the opposite of this, 2^b and equals the cost reduction for each doubling in cumulative installed capacity. A learning rate for hydropower is obtained from the literature. A glance at the literature shows that learning effects are very small compared to other renewable

energy technologies such as wind and solar energy (Jamasp and Köhler 2007). For instance, for hydropower there was a progress ratio of 1.4% between 1975-1993 determined by the OECD (Jamasp and Köhler 2007).

3. Methodology

3.1 Resolution of the analysis

As indicated in paragraph 2.5, a cost-supply curve per region is required as input in the TIMER EPG module. Previously, cost-supply curves for renewable energy technologies have been added to TIMER by Hoogwijk, Gernaat and Koberle using world regional technical potentials (Gernaat 2012; Hoogwijk 2004; Koberle 2013). The technical potential was deduced from the geographical potential which was in turn deduced from the theoretical potential. Hoogwijk calculated the technical potential for biomass, wind and solar energy on half degree resolution and Koberle calculated the technical potential for CSP on half degree resolution. To keep consistency in construction of cost supply curves for inclusion in TIMER, it is tried to obtain the potentials and costs for hydropower on a 0.5 degree resolution as well.

3.2 General steps to construct cost-supply curves

It is tried to develop regional cost supply curves for hydropower systematically using process steps as shown in Figure 11. The steps are numbered and further explained below:

1. First, the annual mean theoretical potential is calculated on the basis of discharge maps and elevation differences based on elevation maps (digital elevation models (DEMs)). The calculations are on a medium level of aggregation, that is on half degree resolution or 30 arc minutes (30'). At the equator, a half degree grid cell (or "cell") is sized approximately 50x50km. Toward the poles, cells decrease in area as the longitudinal distance of a cell decreases. A more in-depth explanation of the method is given in Chapter 4.
2. Second, the geographical potential is determined by adding geographical constraints. In this research it is decided to exclude all protected areas, permanently ice covered areas too densely populated areas and unpopulated areas using aggregated datasets on half degree.
3. Third, the technical potential is estimated. This is done by determining a global ratio of technical potential compared to the theoretical potential. This is called a *Theoretical to Technical ratio*, symbolized as *TTR*). All cells are multiplied with this ratio to obtain the technical potential in each region and each grid cell.
4. Fourth, costs are assigned to individual cells based on their suitability for small or large hydropower. In order to do this, all cells are divided into two categories based on their technical potential. The first category consists of cells where it is assumed that only small hydropower (run-of-river) could be installed. All cells with higher technical potentials are considered suitable for large hydropower (dam and reservoir). For each cell, specific investment costs are assigned based on a cost range. To be precise, the specific investment cost for hydropower development in a cell will be assigned based on the relative technical potential compared to other cells. Next, a capacity factor is calculated for each cell, based on the discharge data. Then, the *LCOE* of hydro-electricity is calculated for each cell. Since hydropower needs no fuel, the fuel costs are zero. Carbon costs are assumed negligible since (in general) most dams have negligible emissions compared to other energy sources such as

coal or gas (IPCC SRREN 2012). Decommissioning costs are assumed low compared to initial investment costs and are also beyond the scope of this thesis. For constant cash flows and constant annual production equation (2.1) can be simplified into (Blok 2007):

$$LCOE\left[\frac{\$}{kWh}\right] = \frac{\alpha[-] \cdot I\left[\frac{\$}{kW \cdot yr}\right] + O \& M\left[\frac{\$}{kW \cdot yr}\right]}{Capacityfactor[\%] \cdot 8760[hrs / yr]} \quad (3.1)$$

In equation (3.1), The initial investments costs are annuitized using the annuity factor

$$\alpha = \frac{r}{1 - (1+r)^{-L}}$$

. The operation and maintenance costs (*O&M*) are added as a percentage

of investment costs to arrive at total annual discounted costs per cell per year:

$$\alpha[-] \cdot I\left[\frac{\$}{kW \cdot yr}\right] + O \& M\left[\frac{\$}{kW \cdot yr}\right]$$

. The *Capacityfactor* indicates the amount of full load

hours that a plant generates energy (Blok 2007). Note that since every variable is assumed constant and the specific investments costs are used, we don't have to compute the installed capacity in order to calculate the *LCOE*.

5. Fifth, the technical potential and *LCOE* are aggregated into regional cost-supply curves.
6. Sixth, the economical feasible potential can be determined by determining a cost-level at which hydropower is competitive to other energy technologies. All potential under this specific cost-level is economic feasible.

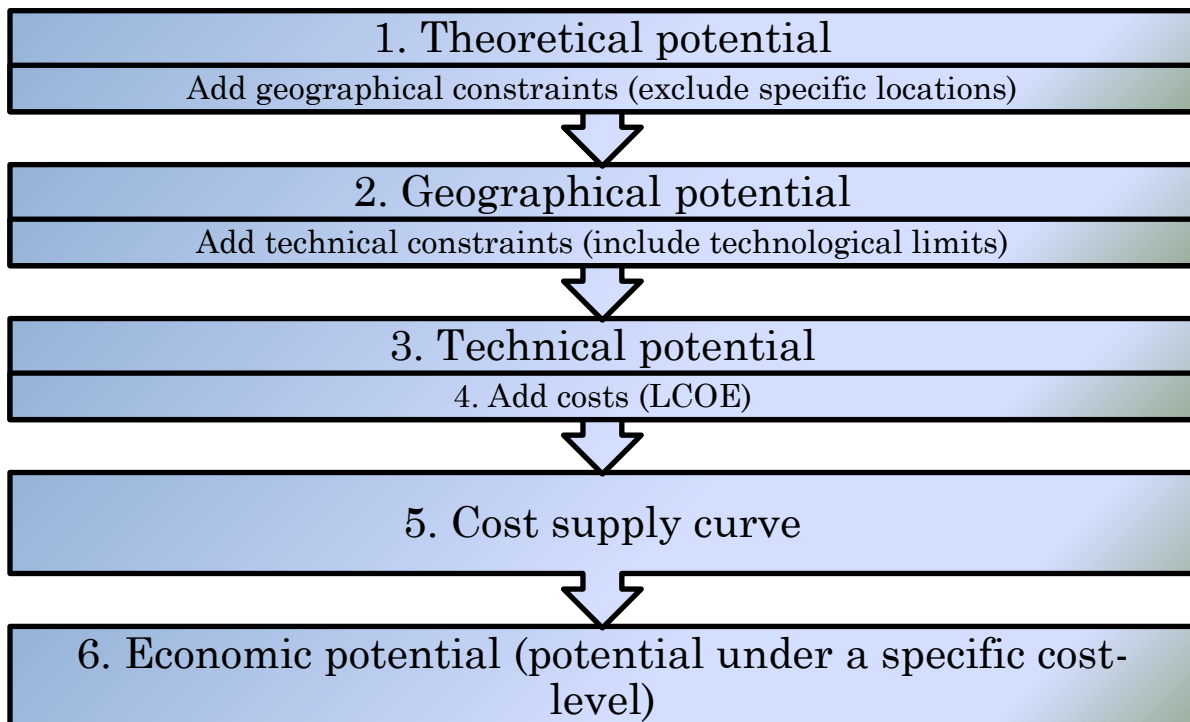


Figure 11: Process steps followed to construct a cost supply curve.

4. Theoretical potential

4.1 Overall method

In this study the concepts *Runoff* and *Discharge* are used in the following way, similar to Lehner et al. (Lehner, Czisch, and Vassolo 2005). Runoff is computed as the difference in the water balance. After water precipitates on the soil, a fraction is absorbed by the soil and a fraction is evaporated. The remainder is runoff. Discharge represents the flow of water in the river after accumulation of runoff has happened. So, the amount of discharge is actually indicating how much water flows in a river, whereas runoff indicates the origin of the water.

The theoretical potential can be calculated by either using runoff or discharge. First, the theoretical potential is calculated using the runoff and the elevation difference down to sea level, similar to method A in Lehner et al. (Lehner et al. 2005):

$$P_{th,cell} = \rho g \cdot Runoff_{cell} \cdot h_{cell} = 9810 \cdot Runoff_{cell} \cdot h_{cell} \quad (4.1)$$

Whereby $Runoff_{cell}$ is the mean annual runoff (m^3/s) in the cell and h_{cell} is the mean elevation down to sea level for runoff in the cell.

The equation for theoretical potential can also be based on the discharge. In order to do this the same approach is used as in method B in Lehner et al. (Lehner et al. 2005). The theoretical potential in a grid cell is calculated with:

$$P_{th,cell} = \rho g \cdot Discharge_{cell} \cdot \Delta h = 9810 \cdot Discharge_{cell} \cdot \Delta h \quad (4.2)$$

Whereby $Discharge_{cell}$ is the mean annual discharge (m^3/s) in the cell and Δh is the difference in elevation associated with the flow of water draining the cell.

It is convenient to apply equation (4.1) since elevation differences (“in” or “between adjacent cells”) are not needed in the equation. However, equation (4.1) can’t be used to calculate the technical potential per cell in order to build cost-supply curves. The logical explanation for this is that we don’t account for the accumulation of runoff to other cells and “associated” potential energy. Equation (4.1) just indicates the origin of the hydropower potential and does not show how much energy is associated with the amount of discharge in the cell. Nevertheless equation 4.1 can be used to compare the results as it is expected that similar outcomes result for the calculated global potential. Results for equation (4.1) are given in section 4.4.

The theoretical potential is calculated with equation (4.2). Two sets of data are required to calculate the theoretical potential:

- Discharge data per cell
- Elevation data per cell

Data on monthly average discharge for each half degree cell is obtained from two different global macro scale hydrological models:

- The Variable Infiltration Capacity model, a.k.a. VIC model
- The Lund-Potsdam-Jena managed Land model, a.k.a. LPJmL model

Data on elevation is obtained from high resolution digital elevation models (DEMs). The following DEMs are used:

- *WWF HydroSHEDS* conditioned DEM on 30 arc second resolution (WWF 2009). This is a hydrological conditioned DEM corrected for elevations on rivers (see Appendix 3).
- *GTOPO30* on 30 arc second resolution (USGS 1996). This DEM is only used for missing elevation data above 60 degrees of latitude.

The DEMs are merged together to obtain one DEM on 30 arc second resolution. The discharge data is on 30 arc minute resolution. Each discharge cell therefore intersects with exactly $60 \times 60 = 3600$ elevation cells. Thus, the calculated elevation differences are aggregated to half degree.

In this thesis three different methods are established to calculate the elevation difference. These methods are explained in paragraph 4.3. Within each of method, different elevation statistics (e.g. mean, median, minimum) and different conditions (e.g. on river network map) can be set for the calculation of the elevation difference. Combining this with two different discharge datasets, a matrix of outcomes for the theoretical potential can be constructed. This matrix is shown in Table 3. In paragraph 4.2 it is described how the discharge data is obtained. In paragraph 4.3 it is described how the elevation differences are calculated.

Table 3: Matrix of outcomes for calculations on theoretical hydropower potential (example).

			Global theoretical hydropower potential (TW)	
Method to calculate elevation difference	Elevation statistics used to calculate elevation difference in cells	Conditions for elevation difference calculation	Using VIC discharge data	Using LPJmL discharge
<i>Method A</i>	Alternative 1: Use mean-minimum elevation		...TW	...
<i>Method A</i>	Alternative 2: Use mean-10 th percentile elevation	
<i>Method A</i>	Alternative 3: Use mean-minimum elevation	Only for cells on river network
<i>Method B</i>	Alternative 1: Use mean elevation	
<i>Method B</i>	Alternative 2: Use 10 th percentile elevation	
<i>Method B</i>	Alternative 3: Use mean elevation	Only cells on river network
<i>Method C</i>	Alternative 1: Use mean elevation	Based on a flow direction grid
<i>Method C</i>	Alternative 2: Use 10 th percentile elevation	Based on a flow direction grid

4.2 Hydrological data

Two discharge datasets are used. Also one runoff dataset was used. In this section, the data is described in more detail.

4.2.1 The VIC discharge dataset

The global mean annual discharge (in m^3/s) in a grid cell is simulated using the Variable Infiltration Capacity (VIC) model, a macro scale hydrological model that calculates water and energy balances for individual grid cells. Basically, VIC calculates the runoff in a grid cell as the difference in precipitation and the sum of evapotranspiration and storage (Gao et al. 2009) (see Figure 12). A routing scheme is used in VIC to transport the runoff and base flow in each grid cell to the outlet of that cell and then into the river system. By adding all contributions of runoff entering into a grid cell over time, the discharge can be simulated for each time step. For the calculations on theoretical potential in this thesis, the annual mean discharge over a 30 year period (from 1971-2000) was used based on simulation on a daily basis using the WATCH climate forcing data as input (Weedon et al. 2011). Furthermore, the influence of existing dams and irrigation on the discharge is not included in this VIC model run. Although it is possible to include existing dams and irrigation, it is beyond the scope of this thesis to investigate this. The influence would most probably not lead to a significant change in the estimated total global discharge that would consequently alter the calculated global hydropower potential (Biemans 2014).

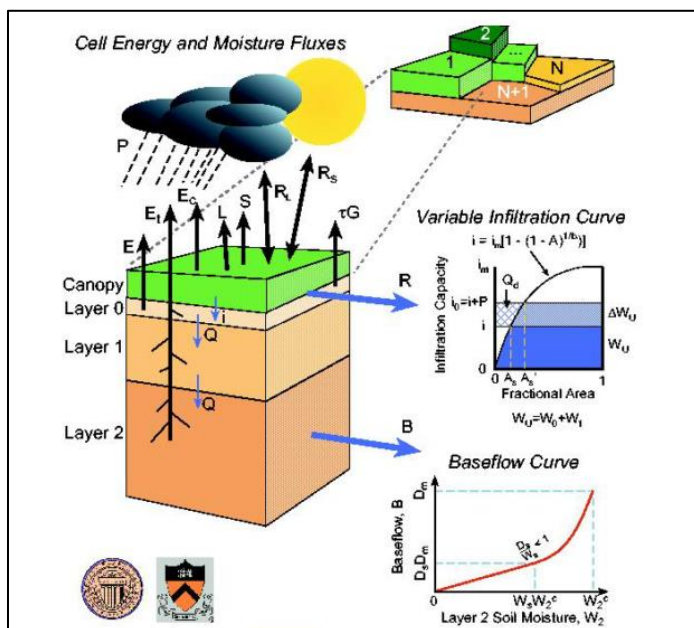


Figure 12: Schematic of the VIC model with mosaic representation of vegetation coverage (Gao et al. 2009).

4.2.2 The LPJmL runoff and discharge dataset

The model LPJmL ("Lund-Potsdam-Jena managed Land") is used to simulate vegetation compositions and distributions as well as stocks and land-atmosphere exchange flows of carbon and water, for both natural and agricultural ecosystems (Badeck et al. 2010). LPJmL simulates processes such as photosynthesis, plant growth, maintenance and regeneration losses, fire disturbance, soil moisture, runoff, evapotranspiration, irrigation and vegetation structure. Compared to VIC, LPJmL is a vegetation model and is less focused on pure water budget modelling than VIC.

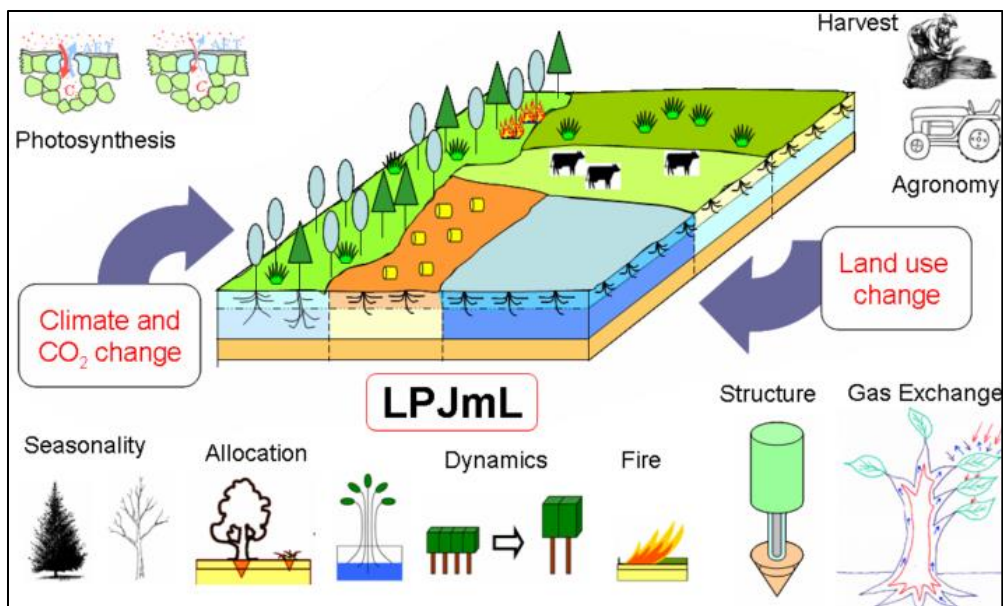


Figure 13: Schematic overview of LPJmL components (Badeck et al. 2010).

Since the IMAGE model uses input data from the LPJmL model, it was decided to use the runoff and discharge data from the LPJmL model as well in order to compare the resulting potentials to the potentials calculated with VIC model data. For the calculations on theoretical potential in this research, the annual mean discharge over a 30 year period (from 1971-2000, the same range as for VIC) based on simulation on a daily basis using the WATCH (climate) forcing data was used. The influence of existing dams and irrigation on the discharge is not included in the LPJmL run.

4.3 Methods to calculate the elevation difference

From a theoretical point of view, the elevation difference (Δh) used in equation 4.2 is equal to the (mean) difference in elevation along the river course(s) located inside a 0.5 degree cell. It is however impossible to obtain this value accurately using elevation data on 30 arc seconds and then aggregating back to 30 arc minutes. Lehner et al. calculates the elevation difference associated with runoff as the difference in mean and minimum elevation in the considered cell (Lehner et al. 2005). For runoff originating from upstream cells, the difference in minimum elevation between the upstream cell and the considered cell is taken. The flow direction is taken from a flow direction grid, showing the main direction where water is drained out of the cell (Figure 14). It is however not clear if this is the most realistic approach. Therefore, the global potential is calculated with this method (Method C), but other methods are used as well to compare the outcomes.

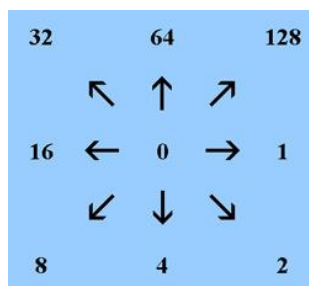


Figure 14: A flow/drainage direction grid (WWF 2009). Binary numbers indicate the outward direction of flow in the middle cell.

The elevation difference is calculated with different approaches and one method is chosen with which to continue afterwards. The elevation differences are calculated as:

- A) Internal elevation differences inside the considered discharge cell.**
- B) Elevation differences compared to the lowest adjacent cell.**
- C) Elevation differences based on flow direction from a flow/drainage direction raster.**

These methods can be described as follows:

A) Internal elevation difference method In this method, the difference in elevation is calculated using elevation data on 30 arc-second resolution *inside* a 30 arc-minute (discharge) cell. To do this we assume that discharge will generally flow from a higher elevation to a lower elevation in the cell. One could for instance assume that, in general, discharge flows from mean elevation to the minimum elevation (or 10th percentile lowest, see Box 2) elevation inside each cell. The reasoning for taking the difference between mean and minimum elevation and NOT the difference between maximum and minimum elevation is that otherwise the potential would be overestimated. This is because not all water flows from maximum to minimum elevation.

As a try to refine this method, the global river network map from WWF HydroSHEDS is overlaid with the hydrological conditioned DEM from HydroSHEDS on 30" resolution. By doing this, only cells on the river network are selected for the calculation of the elevation difference. A zoomed view on the river network is presented in Figure 15. In case of application of a river network map, the reason for taking the difference between mean and minimum elevation and NOT the difference between maximum and minimum elevation is that otherwise the potential would be overestimated once again, since in most cases multiple rivers are located in a 0.5 degree cell and not all these rivers share the same elevation drop (see Figure 15). Instead of mean elevation, it is also possible to use the median elevation.

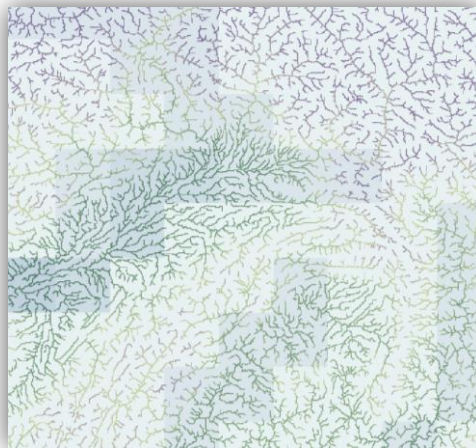


Figure 15: Zoomed view on the HydroSHEDS conditioned DEM on 30 arc-seconds for cells on the HydroSHEDS river network. Large transparent cells are discharge cells on 30 arc-minute resolution.

B) Minimum neighbor method In this method, the difference in elevation between the considered cell and the cell of lowest elevation in the direct neighborhood of 3x3 cells around the considered cell is used. Using the ArcGIS tool *focal statistics*, the minimum

elevation in the neighborhood of 3x3 cells is calculated. Then the elevation difference between the considered cell and this local minimum is calculated. This method is used in the article of Feizizadeh et al. to calculate the potential of the Tabriz Basin in Iran (Feizizadeh and Haslauer 2012). Figure 16 shows part of the HydroSHEDS DEM and a selection of discharge cells. The approach is based on the assumption that a river flows to the lowest elevation in the surroundings. In this method, different statistics can be used, for example the difference in mean elevation between cells, difference in minimum elevation between cells, or difference in 10th percentile elevation between cells. A reason for choosing the minimum or 10th percentile elevation is that a river will naturally flow on relatively lower elevations in the relief as can be viewed in Figure 17.

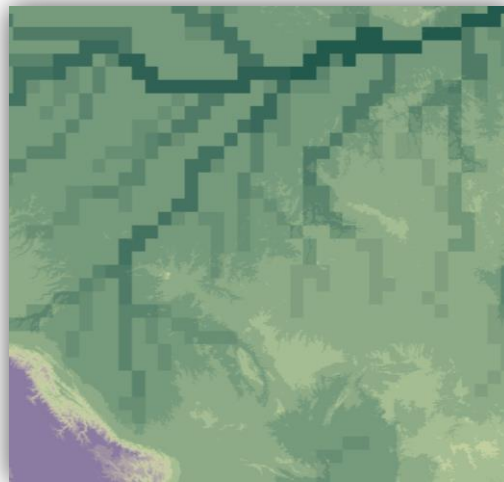


Figure 16: Zoomed view on HydroSHEDS conditioned DEM on 30 arc seconds resolution. Large transparent cells are discharge cells on 30 minute resolution.

- C) Flow/drainage direction method-** In this method the difference in mean elevation between the considered cell and the cell where the discharge is flowing into based on a map of flow/drainage direction is taken (Lehner et al. 2005). There are different flow direction maps for different hydrological models. For instance, DDM30 is used in VIC model simulations and STN30 is used in LPJmL. So in this research, DDM30 is used for VIC data and STN30 is used for LPJmL data.

Box 2: Tenth percentile elevation

In some of the calculation methods described in this chapter, it was chosen to use the tenth percentile lowest elevation for each 0.5 degree cell. The conceptual idea is that this would likely result in a more accurate representation of the elevation of rivers inside the cell since a river will naturally flow on relatively lower elevations in the landscape. The average elevation on which the river flows through the landscape is lower than the mean elevation in the cell as can be seen in Figure 17.

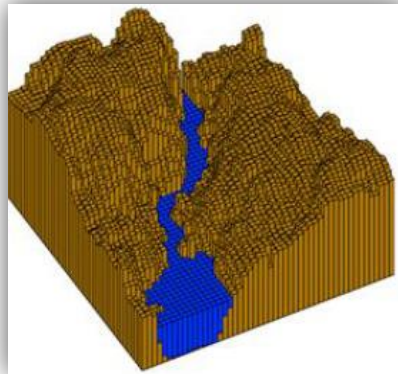


Figure 17: Illustration of an (inundated) river in an elevation raster. The average elevation on which the river flows through the relief is lower than the mean elevation in the cell (adapted from: Oakridge Laboratory, 2013)

4.4 Results using runoff and mean elevation down to sea level

Figure 18 shows the resulting map of global annual mean hydropower potential based on calculations with the runoff from the LPJmL hydrological model and the HydroSHEDS elevation dataset. Areas of high potential are, as expected, found in mountainous regions where runoff and elevation are both high. The global annual average theoretical hydropower potential is computed as the sum of all grid cells and is equal to 8.88TW.

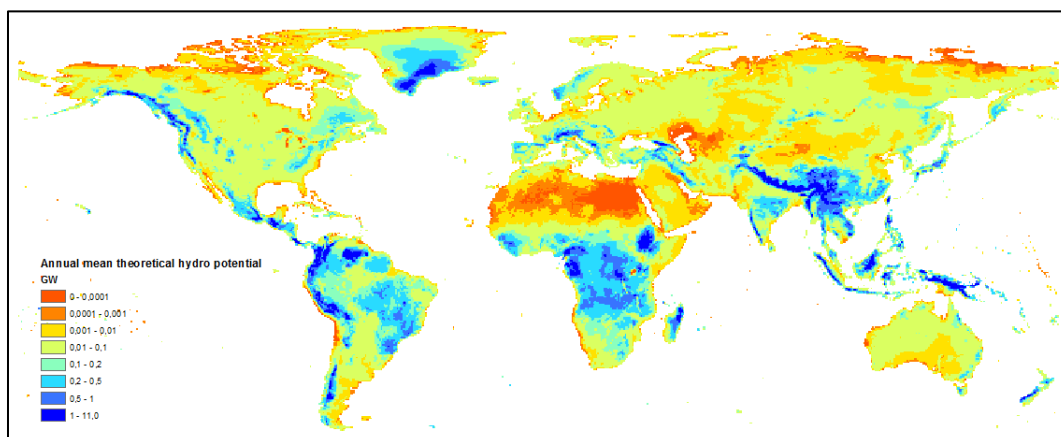


Figure 18: Annual mean theoretical potential for hydropower, based on calculations with annual average LPJmL runoff data on half degree resolution and HydroSHEDS mean elevation data on half degree resolution. Total: 8.88TW.

For comparison, the theoretical potential was also calculated based on monthly runoff from LPJmL and the elevation difference of the considered cell compared to the outlet cell. The outlet cell is the

final grid cell where all the runoff flows back into the ocean. This calculation leads to a total potential of 7.64TW. The total is lower and likely caused by the fact that the final outlet not always equals zero meters above sea level.

4.5 Results using discharge and elevation differences

4.5.1 Method A: Internal elevation difference method

Figure 19 shows the map of calculated hydropower potential using method A. It is clearly visible that the pattern is of a different nature than in Figure 18. Now major river are visible because the discharge is high in these cells. Notably, the distribution of potentials is very different compared to Figure 18. Mountainous regions don't account for the largest potentials anymore, instead low lying regions where a lot of water accumulation is taking place account for the largest potentials. Major rivers are clearly visible on the map. A total potential of 18.66TW results from applying this method by using the difference between median and 10th percentile elevation in each 0.5 degree cell.

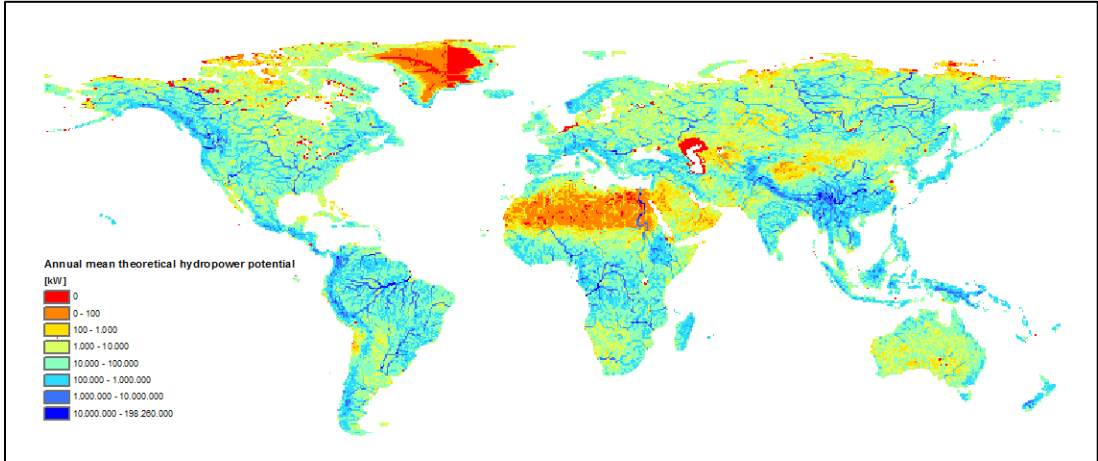


Figure 19: Annual mean theoretical hydropower potential based on calculations with VIC data and difference between median and 10th percentile elevation inside the considered cell. Total: 18.66TW.

Regions of exactly zero potential are marked red. This happens when there is very flat land. Also, at the Aral Sea, there is an area laying several tens of meters below sea level. There, even some negative elevation differences occurred. Those were set to zero.

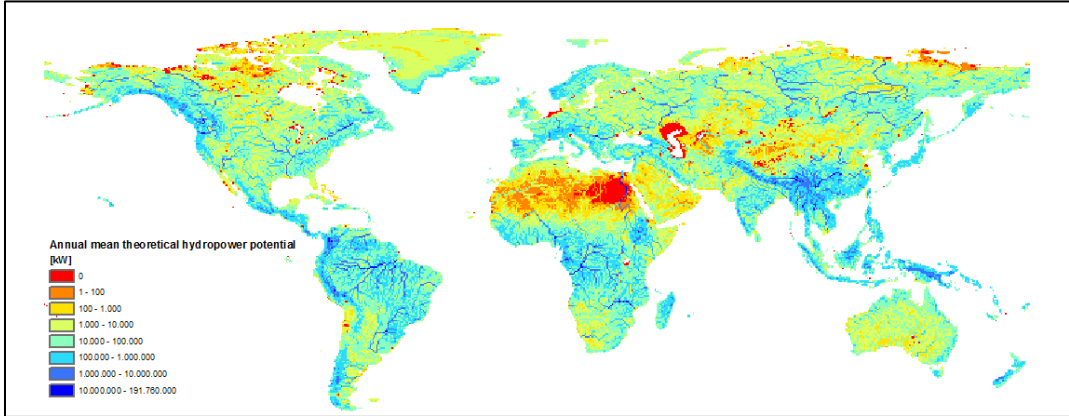


Figure 20: Annual mean theoretical hydropower potential based on calculations with LPJmL data and difference between median and 10th percentile elevation inside the considered cell. Total: 15.12TW.

The resulting map calculated with LPJmL data is shown in Figure 20.

Figure 19 and Figure 20 are clearly looking similar. Zero potential cells occur more when using LPJmL data. The reason that LPJmL has a lower total potential (15.12 TW) is caused by the lower total amount of discharge compared to VIC. Observing that the totals are much higher compared to the calculations with runoff data indicates that the elevation differences are overestimated in this method. In the DEM, there is a wide range of 30s elevation cells inside a half degree cell. This internal elevation range is much larger than the differences in elevation between cells when based on the same statistic (for instance mean, median, 10th percentile or minimum elevation).

The conclusion is therefore that it cannot be assumed that each cell has an elevation drop which can be estimated by using the same elevation statistics (for instance mean, median, 10th percentile or minimum).

4.5.2 Method B: Minimum neighbor elevation method

Figure 21 and Figure 22 show the maps of calculated hydro potential using method B, based on 10th percentile elevation differences in each cell. A total potential of 9.54 TW was calculated with VIC and a total potential of 7.89 TW with LPJmL. The pattern is mostly in accordance with method A with the same areas of high potential. However, there is occurrence of a significant number of red cells all over the map. These are cells in which the elevation difference is zero.

One would expect that a map of drainage/flow direction would point to the lowest elevation in the neighborhood, making the assumption justified that a river flows to the lowest direction in the neighborhood. However, it is important to note that drainage/flow direction maps on 0.5 degree resolution are corrected in different ways for rivers not flowing to their final outlet cell (WWF 2009). As a consequence, in this method a different flow path of the river is obtained. This leads to the outcome that all cells in which the considered cell (“which is the middle cell in the 3x3 neighborhood”) is the lowest cell in the neighborhood, have zero elevation difference and zero potential. It will seem that the river outlet is located inside that cell, where in fact it is not.

This pattern of zero potential cells is the same for both maps since the same method was used.

Application of Method B gives potentials that are a lot lower than in method A. The occurrence of zero potential cells is one important reason that the potential is lower compared to method A. However, the most probable explanation is that the range of elevations inside a half degree cell is almost always higher than the elevation difference elevation between two adjacent cells based on the same elevation statistic (mean, median, 10th percentile or minimum).

Using the mean elevation instead of the 10th percentile elevation doesn't decrease the occurrence of zero potential cells in “red”.

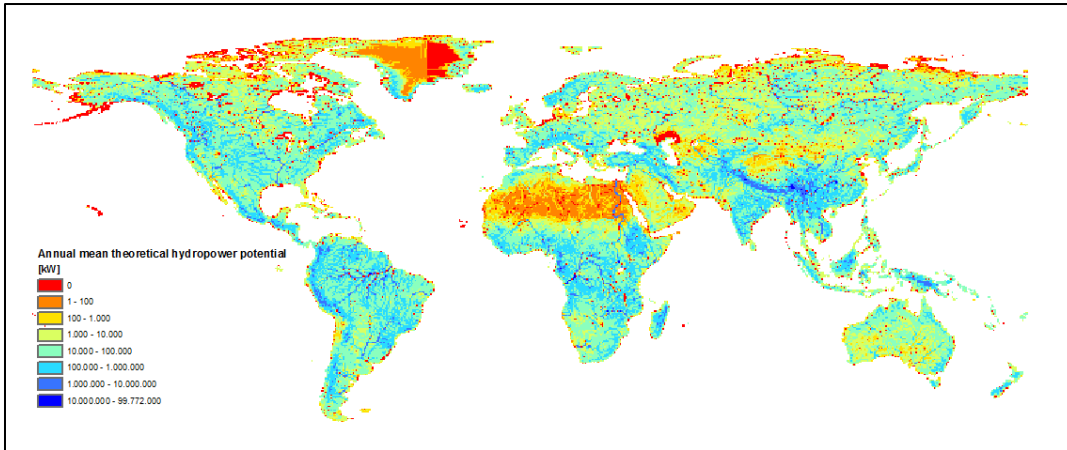


Figure 21: Theoretical hydropower potential calculated with VIC discharge data and elevation differences based on 10th percentile elevation compared to lowest neighbor. Potentials equal to zero are shown in red. Total: 9.54TW.

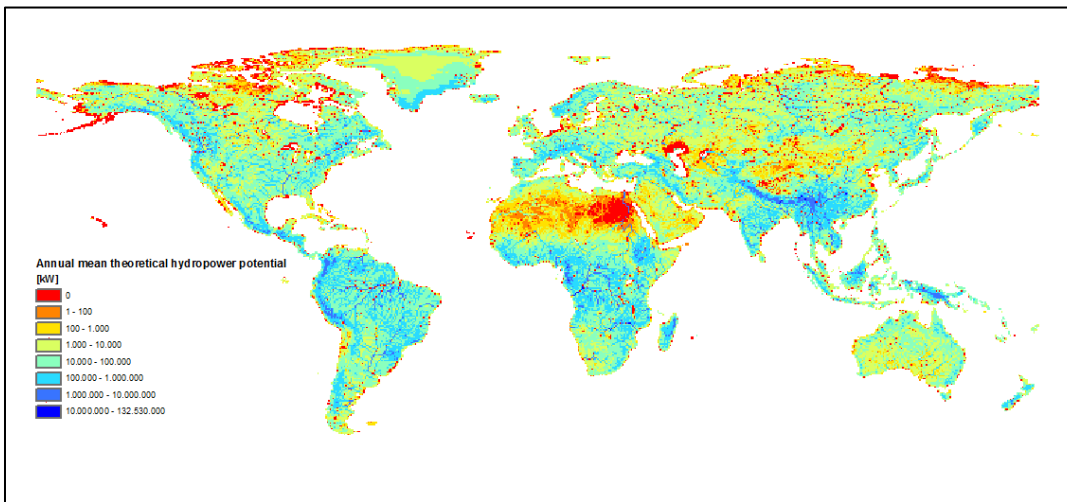


Figure 22: Theoretical hydropower potential calculated with LPJmL discharge data and elevation differences based on 10th percentile elevation compared to lowest neighbour. Potentials equal to zero are shown in red. Total: 7.89TW.

4.5.3 Method C: Flow direction grid elevation difference method

Figure 23 and Figure 24 show the calculated map of hydropower potential using method C and using the 10th percentile elevation. Using VIC data results in a global potential of 6.07 TW. Using LPJmL for the calculation results in 5.74 TW. It is visible that there are a lot more red cells compared to method A and B. In this case, these are cells where either zero or negative elevation differences occurred. All those cells were set to zero² as negative potentials are unusable. The pattern of red cells depends on the drainage direction map used in the elevation difference calculation and is therefore different in the maps.

Furthermore, the amount of red cells on the continent borders is less with LPJmL data. The reason is that a different flow/drainage raster was used to calculate the elevation differences.

² For VIC, the potential was negative in 6% of the cells (4251 cells out of 66663 cells) and not setting negative values to zero results in 5.19TW. For LPJmL, the potential was negative in 9% of the cells (5987 cells out of 66663 cells) and not setting negative values to zero results in 5.00TW.

The obtained global potential is much lower compared to both method A and B. The reason for a lower potential is the occurrence of negative and zero elevation differences. Negative elevations are obtained because the flow direction map is not compatible with the elevation map. In other words: the DEM predicts another flow path of the rivers though the DEM as the flow direction map does.

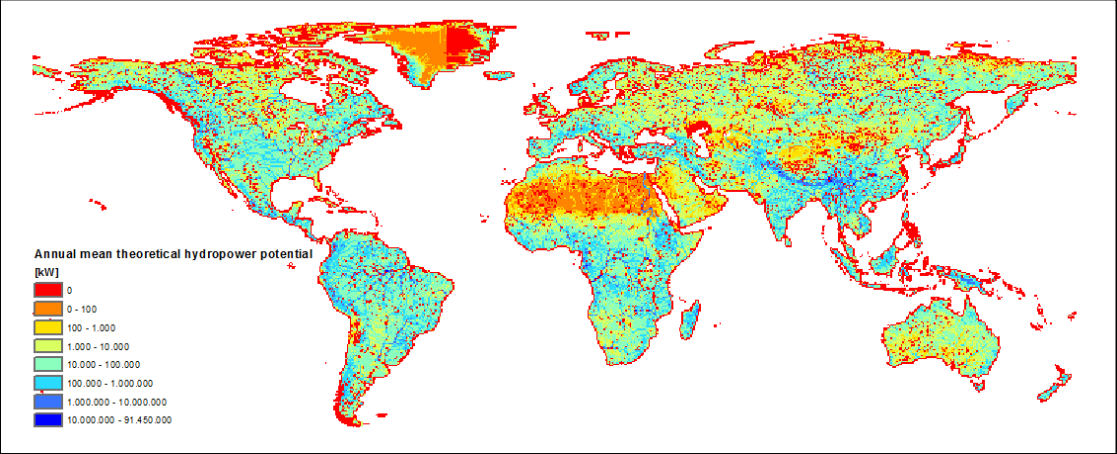


Figure 23: Annual mean theoretical hydropower potential calculated with VIC discharge data and elevation differences based on ddm30 using the 10th percentile elevation in each 0.5 degree cell. Negative values are set to zero and marked red. Zero values on continent borders are also shown in red. Total: 6.07 TW.

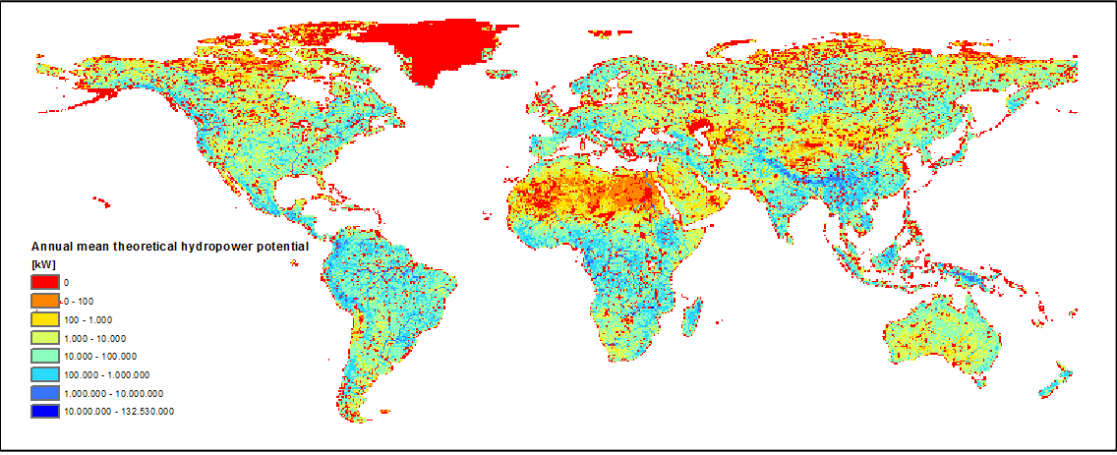


Figure 24: Annual mean theoretical hydropower potential calculated with LPJmL discharge data and elevation differences based on stn30 using the 10th percentile elevation in each 0.5 degree cell. Negative values are set to zero and marked red. Zero values on continent borders are also shown in red. Total: 5.74TW.

4.6 Overview of calculated global theoretical potential in case of different methods

Table 4 gives the results of my calculations for the theoretical potential in case of methods with different discharge and elevation datasets. Method A gives higher results than method B and C. Method C gives the lowest results. Applying a river network map to select cells on rivers also lead to a lower global estimate.

Table 4: Calculated annual global theoretical hydropower potential (in TW) using different methods and discharge datasets.

Method nr.	Method to calculate elevation difference	DEM used	Elevation difference	Conditions for elevation difference	Calculated global theoretical hydropower potential (TW)	
					VIC model discharge	LPjML discharge
1	A	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	mean elevation - minimum elevation		31.01	25.05
2	A	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	mean elevation - minimum elevation	on HydroSHEDS river network	21.68	17.52
3	A	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	mean -10th percentile elevation		21.27	17.44
4	A	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	median - 10th percentile elevation		18.66	15.12
5	A	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	10th percentile elevation - minimum elevation		9.85	8.00
6	B	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	mean elevation - mean elevation of lowest adjacent cell		16.91	14.10
7	B	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	mean elevation - mean elevation of lowest neighbor	on HydroSHEDS river network	13.53	11.2
8	B	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	minimum elevation - minimum elevation of lowest neighbor		7.31	6.05

9	B	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	minimum elevation - minimum elevation of lowest neighbor	on HydroSHEDS river network	7.22	5.99
10	B	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree.	10th percentile elevation - lowest adjacent 10th percentile elevation		9.54	7.79
11	C	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree	mean elevation - mean elevation adjacent cell	flow direction based on stn30	Not a consistent method	7.61
12	C	HydroSHEDS (30s) + GTOPO (30s) for missing elevations above 60 degree. Aggregated to 30min = 0.5 degree	mean elevation - mean elevation adjacent cell	flow direction based on ddm30	7.31	Not a consistent method
13	C	DEM used: HydroSHEDS (30s) + GTOPO (30s) for missing elevation above 60 degree. Aggregated to 30min = 0.5 degree.	10 th percentile elevation - 10 th percentile elevation adjacent cell	flow direction based on ddm30	6.07	Not a consistent method
14	C	HydroSHEDS (30s) + GTOPO (30s) for missing elevation above 60 degree. Aggregated to 30min = 0.5 degree.	10 th percentile elevation - 10 th percentile elevation adjacent cell	flow direction based on stn30	Not a consistent method	5.74

4.7 Comparison between methods and comparison to literature

The literature range of theoretical potentials is 3.5TW-10TW, see Table 5. This range is used to decide upon the most realistic method to continue with. It is remarkable that some of the literature sources don't site the original source. Furthermore it can be seen that the global potential is still uncertain to some degree as different method results in different estimates. It can be observed from Table 4, that some of the calculations are in range of the literature values as shown in Table 5. The outcomes of method A are significantly higher and therefore assumed unrealistic. The outcomes of method B are also high compared to literature; especially using VIC. Method C comes closer to estimates seen in the literature.

Table 5: Literature values on global theoretical hydropower potential.

Reference	Global total theoretical hydropower potential (TW)	Method:
(Lehner et al. 2005)	5.99 TW (52,500 TWh/yr)	Calculated using a drainage direction map in combination with a hydrological model (WaterGap) and a DEM (Hydro1K on 1km resolution) aggregated to 0.5 degree resolution.

(Fekete et al. 2010)	3.5 TW (30,660 TWh/yr)	Based on global average discharge of 40.000 km ³ /year (or 1.27×10 ⁶ m ³ /s) to the oceans and a runoff weighted elevation of 275meters above sea level.
(Schiermeier Q, Tollefson J, Scully T, Witze A 2008)	>10 TW (> 87,600 TWh/yr)	Does not cite original source
(WEC 2010)	4.5 TW (39,842 TWh/yr)	Country surveys, methodology is not explained. Potentials are based on IJHD.
(IJHD 2013)	4.95 TW (43,423 TWh/yr)	Country surveys, methodology is not explained.
(Resch et al. 2008)	4.8 TW	Does not cite original source.

4.8 Regional comparison to survey data

It provides more insights to compare the results per region. This comparison is made in Table 6. Method A is considered as too high and is not shown here. It can be seen that the totals from Table 6 are close to the values reported in IJHD (2013). In general larger regions are overestimated, whereas smaller regions are underestimated. This likely is caused by the coarse resolution of the analysis. Also, the difference in regional output between the two hydrological models is remarkable.

Cells in green are within 2x the reported values in IJHD. Therefore values in green are considered more reliable compared to values in a black color or red color. Values in red are considerably deviating from reported values in IJHD. It is likely that the method failed to accurately represent these regions. To solve this, correction factors were added later on. Also note that the potentials of Africa could not be derived from survey literature as not enough data was provided in the journal.

Table 6: Comparison of calculated theoretical potentials and comparison with International Journal of Hydropower and Dams 2013.

Regional theoretical potential							
IMAGE Region nr.	IMAGE Region	Theoretical potential as reported in IJHD 2013 (TWh)*	Method C with VIC data and with 10th percentile elevation (TWh)	Method C with LPJmL data and with 10th percentile elevation (TWh)	Method B with VIC data and with 10th percentile elevation (TWh)	Method B with LPJmL data, and with 10th percentile elevation (TWh)	*Notes on data IJHD 2013
1	<i>Canada</i>	2250	3645	2980	6080	4204	
2	<i>USA</i>	4488	3836	2563	5593	3312	
3	<i>Mexico</i>	430	712	786	1213	1127	
4	<i>Central America</i>	862	242	278	337	347	*Calculated as North & Central America minus USA and Canada
5	<i>Brazil</i>	2280	5068	4746	7496	6339	
6	<i>Rest of South</i>	5613	4633	4916	7728	7317	* Calculated as South America minus Brazil

	<i>America</i>						
7	<i>Northern Africa</i>	N/A	493	425	850	580	* Not enough data available
8	<i>Western Africa</i>	N/A	7112	8573	10933	10360	* Not enough data available
9	<i>Eastern Africa</i>	N/A	2765	2573	4077	3288	* Not enough data available
10	<i>South Africa</i>	N/A	342	229	533	285	* Not enough data available
11	<i>Western Europe</i>	2070	1217	1167	1903	1673	* Calculated as Netherlands, Belgium, Luxemburg, Germany, UK, Iceland, France, Italy, Spain (peak), Portugal, Austria (peak), Denmark, Norway, Sweden, Finland, Greece, Irish Rep, Switzerland
12	<i>Central Europe</i>	339	443	415	673	545	* Calculated as Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Rep, Estonia, Hungary, Latvia, Lithuania, Macedonia (FYR of), Poland, Romania, Slovakia, Slovenia, Serbia
13	<i>Turkey</i>	433	323	241	629	365	
14	<i>Ukraine +</i>	54,2	100	83	148	105	* Calculated as Ukraine, Moldova and Belarus
15	<i>Asia-Stan</i>	971,9	557	285	859	410	* Calculated as Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan
16	<i>Russia +</i>	2496	3796	3010	5887	4261	* Calculated as Russia, Armenia, Azerbaijan, Georgia
17	<i>Middle East</i>	N/A	536	472	975	668	* Not enough data available
18	<i>India</i>	2638	2854	2630	4391	3503	* India theoretical potential India from WEC 2008
19	<i>Korea</i>	52	41	45	73	54	* Calculated as South Korea. North Korea not available
20	<i>China +</i>	6243	5868	4765	10470	7439	* Calculated as China, Taiwan, Mongolia
21	<i>South eastern Asia</i>	1261	1802	2033	3108	3167	* Calculated as Cambodia, Laos, Malaysia, Myanmar, Philippines, Thailand, Vietnam
22	<i>Indonesia +</i>	2322	1314	1780	1991	2299	* Calculated as Indonesia and Papua New Guinea
23	<i>Japan</i>	718	94	112	153	131	
24	<i>Oceania</i>	483	740	687	1213	906	* Calculated as Australia/Oceania minus Papua New Guinea
25	<i>Rest of South Asia</i>	1865	1810	1497	2348	1802	* Calculated as Pakistan, Afghanistan, Bhutan, Nepal
26	<i>Southern Africa</i>	N/A	2524	2938	3492	3625	* Not enough data available
27	<i>Greenland</i>	550	261	23	471	979	
	<i>Africa total</i>	4426	13236	14738	19885	18138	*Total for Africa
	<i>Global Total</i>	42844	53130	50252	83623	69091	* Some countries are estimated in IJHD in order to calculate continent totals, therefore this regional breakdown does not add up to the total of 43,423 TWh in IJHD.

The results are graphically compared in Figure 25. It is visible that method A overestimates the potential in the regions. Method C is better than method B in predicting the potential of large regions such as Brazil and China. The largest deviations from literature are Japan, Central America, West Europe and Africa. Japan, West Europe and Central America are underestimated compared to literature from the WEC and IJHD. Africa is overestimated compared the total of 4426 TWh reported in IJHD. It can be seen in Table 6 that only West Africa has a potential of more than 7000 TWh according to the calculations.

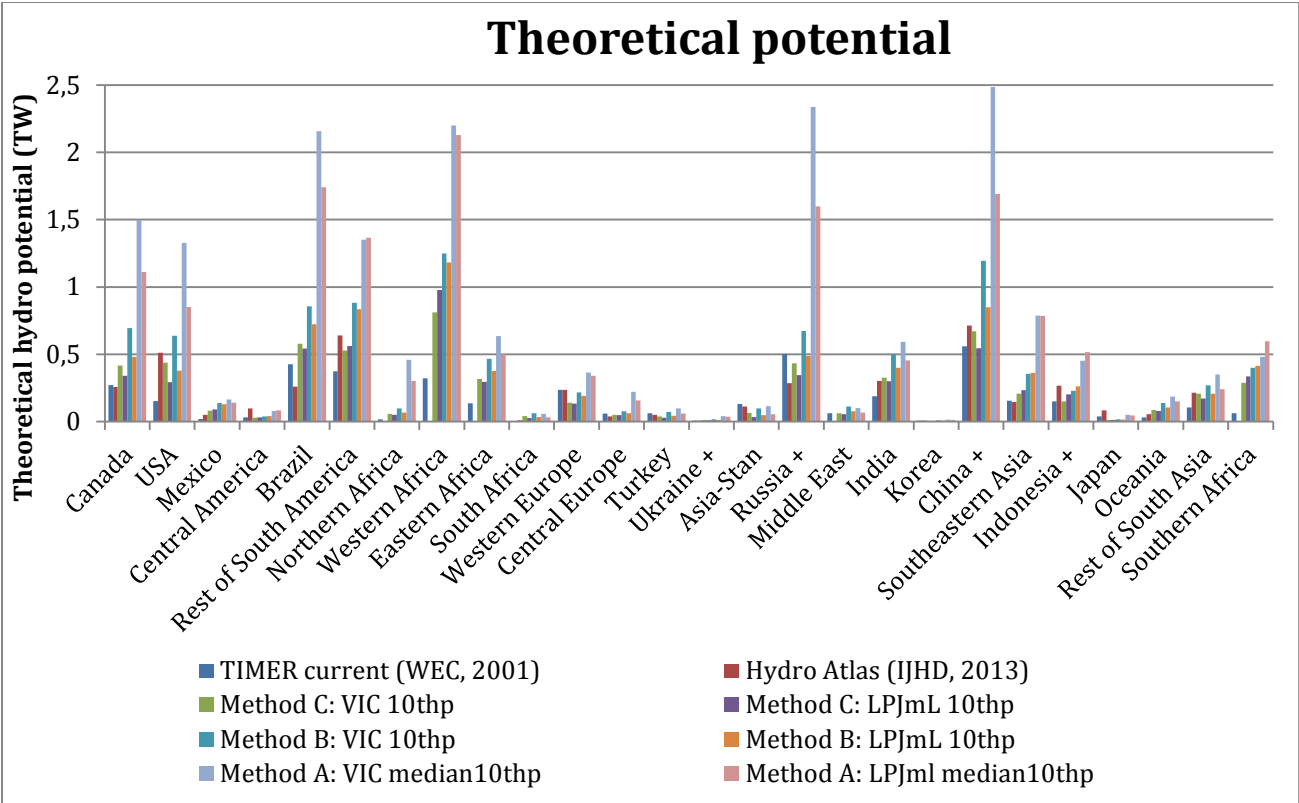


Figure 25: Comparison of literature values per region and calculated values per region for the theoretical hydropower potential.

Comparing the total potential and the regional potentials to the literature, it was decided to base the cost supply curves on method C for theoretical potential. The outcomes of method A are considered too high as explained before. The reason to prefer method C above method B is that method C also preserves flow direction and therefore more accurately represents the “true potential” of a cell.

5. Geographical potential

The global geographical potential for hydropower is equal to the theoretical potential with the exclusion of all areas that are non-suitable for hydropower development based on geographical constraints. In this study, the following geographical constraints are included:

- **Ice cover:** Areas with permanent ice cover (e.g. in Greenland and Canada) are assumed unsuitable for hydropower development. Data on ice cover on half degree resolution was taken from the IMAGE 2.4 GLCT (Global Land Cover Type) dataset for the year 2005. Even

though ice cover is subject to changes over time, it is assumed that the most important areas will be excluded using this dataset.

- **Ecoregions:** All protected areas, that is parks, wildlife protection areas etc. cannot be used for hydropower development and need to be excluded from the analysis (Craig et al. 2010; Monk et al. 2009; Punys et al. 2011). Before the construction of hydropower plants, a site assessment is done to ensure that all environmental considerations are being met. For example, no wildlife may be threatened by construction of a dam. Fish migration (e.g. salmon) is often a reason that areas are protected. To implement this constraint, an dataset of global protected areas was obtained from the World Database on Protected Areas (UNEP WCMC & IUCN 2013).
- **Maximum population density:** The population in each 30' grid cell has to be smaller than 10^7 (or about 250m^2 per person) (Fekete et al. 2010). This is to limit the problem of resettlement in densely populated areas that might occur when a large reservoir is build. Resettlement happens when a large dam is constructed and a large area is flooded in order to create a reservoir. Population data from the IMAGE 2.4 model was used to implement this constraint.
- **Minimum population density:** The average population in every 5×5 grid cell neighborhood (on the 30' longitude \times latitude grid) had to be $>10^3$ to eliminate potential sites in unpopulated regions (Fekete, 2010). The reason is that the demand for electricity is not enough to construct a hydropower plant. For example, a relatively small plant of 1 MW with a capacity factor of 40% produces 3,500,000 kWh annually, which is enough for 1000 households (assuming $3500\text{ kWh household}^{-1}$). Population data from the IMAGE 2.4 model was used to implement this constraint.

Table 7 shows the separate impact of the geographical constraints on the global hydropower potential. The two constraints of most impact are exclusion of all the protected areas and the exclusion of unpopulated areas. A visual map of the constraints used is given in Appendix 4.

Table 7: Overview of impacts of the constraints used to calculate the geographical potential.

Method for theoretical potential	Method C: 10 th percentile VIC	Method C: 10 th percentile LPj mL
Global theoretical potential (TWh)	53130	50252
Exclude ice covered areas (TWh)	52850	50209
Exclude protected areas (TWh)	44561	41844
Exclude too densely populated areas (TWh)	44546	41830
Exclude unpopulated areas (TWh)	39563	38099
Global Geographical potential (TWh)	39563	38099

6. Technical potential

6.1 Determining factors of the technical potential

The technical potential for hydropower is equal to the amount of geographical potential that can be produced taking technical limits into account. Therefore, all losses in the electro-mechanical

equipment of the hydropower plant need to be taken into account. The efficiency of a turbine is about 85% for the conversion of mechanical energy into electricity (Craig et al. 2010; IEA 2012). For the entire system, from kinetic energy of the water to the grid, an efficiency is assumed of 70% (Craig et al. 2010). The efficiency of the turbine is related to the type of turbine and technological progress made over time. This is explained in more detail in Appendix 5. It is not only the efficiency that limits the amount of generation that is technically possible. It can be reasoned that hydropower plants need to be separated by a certain distance from each other in order not to interfere heavily with another dam's operation (e.g. water uptake) and the natural discharge regime of the river. The natural variability of discharge is another factor to take into account for estimating the amount of generation that could be realized. Moreover, hydropower plants simply cannot be built on every location along the river. Hydropower reservoirs are built on relatively ideal locations where a natural valley or rock formation forms a "V-shape" where a dam can be constructed.

All restrictions mentioned above result in a limit of the maximum amount of energy that could be extracted using hydropower at a specific site. At this level of aggregation, we don't have the means to, for instance, estimate spacing of dams along rivers or estimate the maximum amount of dams inside a cell and from this estimate a technical potential. Instead, the country survey data from the International Journal of Hydropower and Dams is examined in order to obtain a statistical ratio of the technical potential compared to the theoretical potential.

6.2 Determination of a theoretical to technical ratio (TTR) for hydropower

A comparison between the technical potential and theoretical potential is made here in order to obtain a *Theoretical to Technical potential Ratio (TTR)* for use in the calculations on the technical potential. We use the International Journal of Hydropower and Dams (2013) for the installed capacity, generation and potentials. Data and calculated percentages are presented in Table 8.

The technical potential worldwide is $15,816 \text{ TWh yr}^{-1}$, which is 36.4% of the theoretical potential. Looking at the ratios of technical potential to theoretical potential on the continental level, we observe that a number of large continents (i.e. Africa, Asia, Europe and South America) have ratios close to this number. For this study on global scale, this ratio is considered a reasonable estimate to calculate the technical potential. Therefore, this number is used as the *TTR*. Every 0.5 degree cell is multiplied with this ratio to give a rough estimate of the realizable technical potential.

Note: One could argue to use the technical to theoretical ratios on the continental level or even on individual country level. Using TTR's on country level seems possible, however it leads to a very high TTR (72.8%) for Russia and a very low ratio for USA (11.9%). This leads to unrealistic predictions of the LCOE as this is determined by the technical potential calculated here (see Section 7 for capacity factor formula). Using TTRs on continental level also would lead to higher costs in the USA compared to other regions such as Africa and is considered as an unrealistic approach.

Table 8: Data on installed capacity, actual generation, theoretical potential and technical potential for hydropower (IJHD 2013). All percentages are based on own calculations using the data in this table. Numbers shown in red are above 100% and considered as errors in the provided data. A * indicates that only the capacity was available and a 40% capacity factor is assumed.

	Installed Capacity (MW)	% of global capacity	Actual generation in 2011 (TWh/yr)	Actual generation compared to theoretical potential (%)	Theoretical potential (TWh/yr)	Share of theoretical cap. that is implemented (%)	Tech. potential (TWh/yr)	Tech. Potential compared to theoretical potential (%)
Africa	26.000	2,6%	115	2,6%	4.426	5,1%	1.581	35,7%
Asia (incl. Russia, Turkey)	470.000	46,5%	1.593	8,1%	19.717	20,9%	8.152	41,3%
Australia/Oceania	13.000	1,3%	42	6,4%	657	17,3%	185	28,2%
Europe (excl. Russia, Turkey)	184.000	18,2%	532	17,0%	3.129	51,5%	1.205	38,5%
North and central America	172.000	17,0%	681	9,0%	7.600	19,8%	1.886	24,8%
South America	145.000	14,3%	707	9,0%	7.893	16,1%	2.807	35,6%
World total	1.011.000	100%	3.672	8,5%	43.423	20,4%	15.816	36,4%
China	249000	24,6%	861	14,2%	6083	35,9%	2474	40,7%
Brazil	86983	8,6%	415	18,2%	2280	33,4%	911*	40,0%
USA	79500	7,9%	277	6,2%	4488	15,5%	536*	11,9%
Canada	75200	7,4%	355	15,8%	2250	29,3%	823*	36,6%
Russian Federation	46000	4,5%	165	7,2%	2295	17,6%	1670	72,8%
India	43000	4,3%	130	4,9%	2638	14,3%	660	25,0%
Norway	30674	3,0%	143	23,8%	600	44,8%	300	50,0%
Japan	27987	2,8%	95	13,3%	718	34,2%	285	39,7%
France	23000	2,3%	37	18,7%	200	100,7%	120	60,0%
Turkey	20069	2,0%	71	16,5%	433	40,6%	216	49,9%
Italy	17800	1,8%	43	22,6%	190	82,1%	60	31,6%
Sweden	16203	1,6%	78	39,0%	200	71,0%	130	65,0%
Venezuela	15126	1,5%	90	12,3%	731	18,1%	261	35,6%
Switzerland	14514	1,4%	40	31,9%	125	101,7%	41	32,8%
Austria	13200	1,3%	38	41,9%	90	128,5%	56	62,2%
Mexico	12249	1,2%	26	6,1%	430	25,0%	135	31,4%
Vietnam	12500	1,2%	68	22,6%	300	36,5%	123	41,0%
Argentina	11148	1,1%	39	11,1%	354	27,6%	130	36,7%

6.3 Other technical constraints

There are two other technical constraints applied to calculate the technical potential.

- The theoretical potential in a cell has to be ≥ 1000 kW. This is assumed as minimum required stream power to provide enough energy to the turbine. In the USA new stream reach development, Oakridge laboratory estimates potentials of streams with nominal capacity greater than 1MW. This also corresponds to the minimum capacity of a small hydropower plant (IEA ETSAP 2010).
- The elevation difference in a cell has to be ≥ 15 m (Fekete et al. 2010). This is because enough slope has to exist inside a cell. Otherwise large areas have to be flooded in order to create a sufficient reservoir size (Fekete et al. 2010). For run-of-river it is reasoned that a minimum slope is also needed to provide a sufficient head. It was chosen to calculate the difference between medium elevation and minimum elevation on the river network in every cell and check if this was ≥ 15 m. This is done because a river flows on lower elevation in the landscape.

6.4 Resulting global technical potential

Table 9 shows that calculated global technical potential. The technical potential is around one third of the geographical potential. The last row shows the technical potential after corrections for some of the regions. This is explained in the section 6.4.1.

Table 9: Overview table of calculated global values of theoretical, geographical and technical potential.

Method C with 10 th percentile	Method 13: VIC discharge	Method 14: LPjML discharge
Global Theoretical potential (TWh)	53130	50252
Global Geographical potential (TWh)	39563	38099
Global Technical potential (TWh)	13980	13476
Global Technical potential (TWh) (after corrections for Africa, Central America, Europe and Japan)	12589	11754

6.5 Comparison to literature

Figure 26 shows the regional comparison of technical potential. Data on Africa (except South Africa) is not available and therefore not shown in the graph. In is visible that the technical potential of relatively large regions (e.g. Brazil, China, Southeastern Asia and India) are estimated close to IJHD. Underestimations compared to IJHD happen in Japan, Central America and West Europe. A plausible reason for these deviations is the coarse resolution of the analysis. Smaller regions are more prone to errors as they consist of a smaller number of cells.

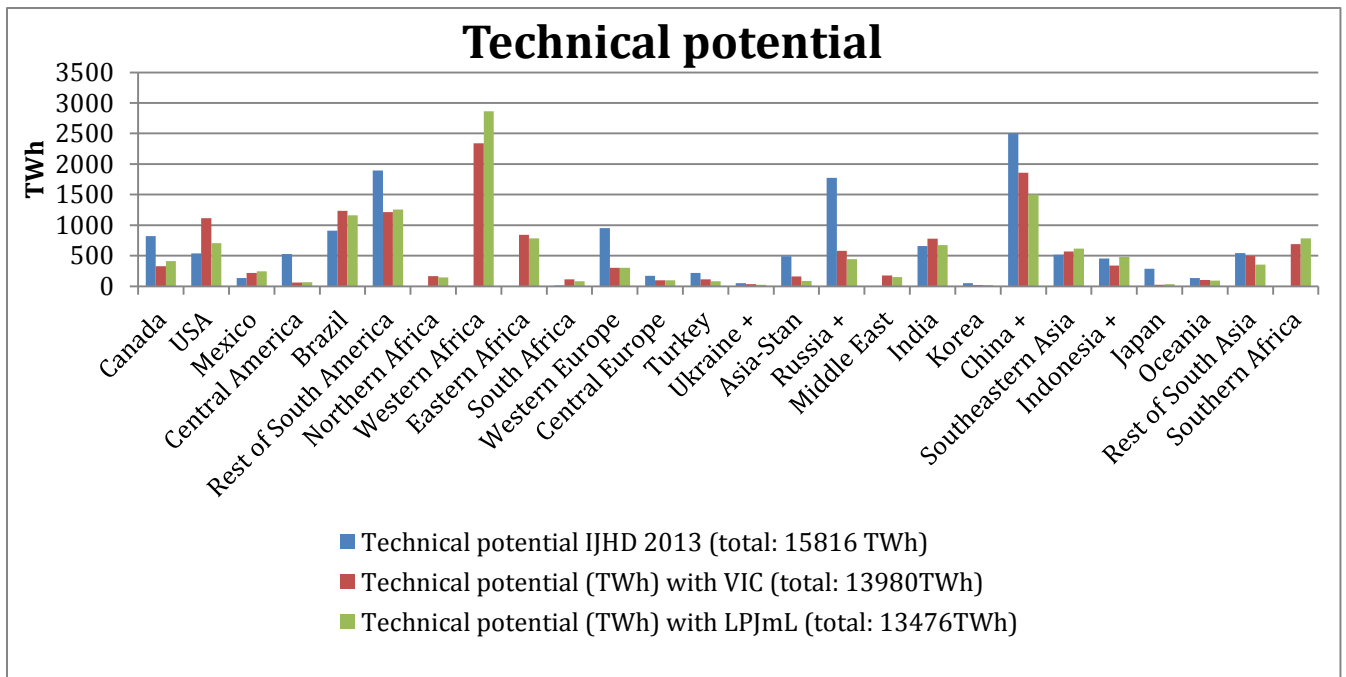


Figure 26: Comparison of technical potential with literature and between calculations. When IJHD only gave the capacity that is technically possible, a capacity factor of 40% is assumed.

6.5.1 Technical potential corrections for deviating regions

Some regions have a deviation in technical potential compared to IJHD that is considered unrealistic high. Therefore, the following regions were corrected:

- All African regions (except South Africa), i.e. Northern Africa (7), Western Africa (8), Eastern Africa (9), and Southern Africa (26). The calculated technical potential was several factors **higher** as the technical potential reported in IJHD (2013) (i.e. 4426 TWh for Africa in total). To correct for this, a lower TTR was used, i.e. 15% instead of 36.4%.
- Central America (4) and Japan (23). The calculated technical potential was several factors **lower** as the technical potential reported in IJHD (2013). To correct for this, the technical potential reported in IJHD (2013) was used.
- Western Europe (11) and Central Europe (12). The calculated technical potential was several factors **lower** as the technical potential reported in IJHD (2013). To correct for this, a higher TTR was used, i.e. 60% instead of 36.4%.

The resulting global technical potential after correction is given in Table 9.

7. Economical potential

7.1 Costs versus parameter relationships for hydropower

In order to construct cost supply curves, it was tried to relate specific investment costs of hydropower to physical parameters, such as the installed capacity (MW), discharge Q (m^3/s), head (m), reservoir size (m^3) or others. Therefore a literature review on investment costs for about 100 hydropower dams was carried out. It was found very challenging to establish cost-correlations using a dataset of dams. In the first place, it was a difficult to track down consistent data on investment costs for different kinds of hydropower dams that were all build during different decades. Secondly,

and most importantly, in a lot of cases hydroelectricity production is not the main purpose of a dam and the dam only has installed a relatively small turbine. Thus, the investment costs of the generator will only be a very small proportion of the total investment. This can lead to a large overestimation of the specific investment costs.

Other research has been carried out in this field nowadays and different cost-relationships can be found in literature (Black & Veatch 2012; IRENA 2012; ORNL 2013b).

For instance, researchers from Oakridge laboratory have done a regression analysis on a dataset of existing dams in the USA to obtain the following cost-equation for new site development of hydropower (ORNL, 2013b):

$$\text{Initial capital cost of new site development} \left(\frac{\text{US\$2011}}{\text{kW}} \right) = 1.2 \times 110,168 H^{-0,35} P^{-0,3} \quad (7.1)$$

Whereby H is the design head in meters and P is the installed capacity in kW (ORNL 2013b). This equation is graphed in Figure 27 for some choices of design head. It can be observed that the investments costs decrease exponentially with higher capacity. Also a higher head dam has lower specific investment costs than a low head dam. It should be emphasized that this is only a general trend and that there always might be exceptions.

In order to use equation (7.1) to calculate costs in a grid cell, a correlation between H or P and the theoretical potential in a cell and/or elevation data in a cell is needed. However no correlation was found between elevation statistics (e.g. elevation differences) in a half degree cell and average dam height in a half degree cell. There was also no correlation found between theoretical/technical potential of a cell and installed capacity. Thus a different approach is taken and it was decided to estimate the costs per grid cell using as cost range as described in the methodology.

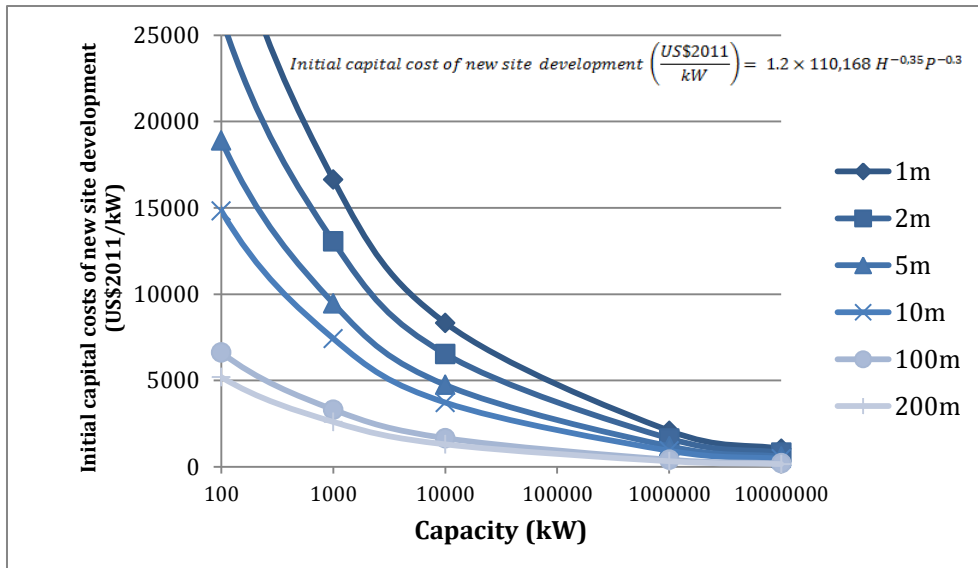


Figure 27: Relationship between initial capital costs of new site development and capacity for different dam heads (preliminary results Oakridge Laboratory) (ORNL 2013b).

7.2 Cost ranges for small and large hydropower

In this paragraph the cost ranges will be determined by looking at the literature. Figure 28 shows a summary of the installed costs for hydropower projects from a range of studies (IRENA 2012). Small and large hydro are the both included in the cost range. Also PHS is included.

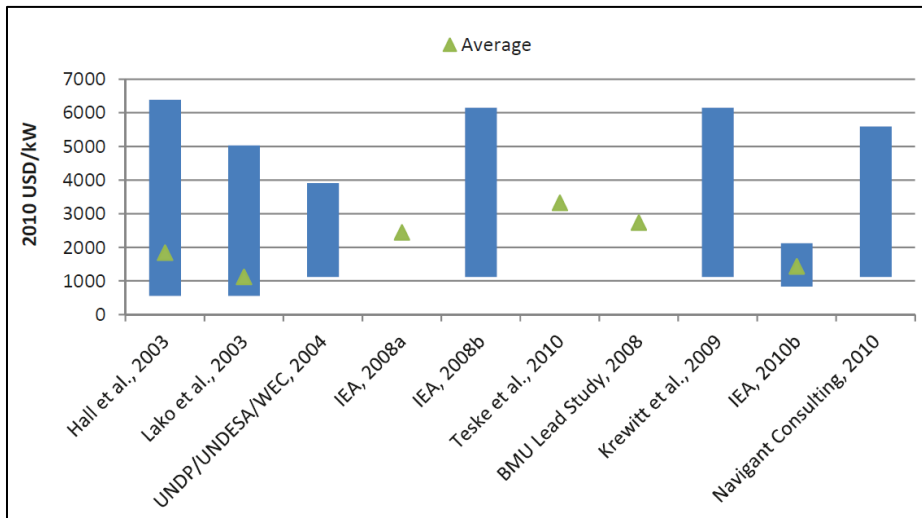


Figure 28: Summary of the installed costs for hydropower projects from a range of studies (IRENA 2012)

In order to obtain reliable estimates for the specific investment costs, the following literature sources are compared:

- Data ranges on specific investment costs from the International Renewable Energy Agency (IRENA 2012).
- Cost ranges from the International Energy Agency Energy Technology System Analysis Programme (IEA ETSAP 2010).
- Cost data from the Global Energy Assessment (GEA 2012).

Note: TIMER uses US\$ 2005 currency. Thus, all costs have been converted to this currency using an inflation calculator (Bureau of Labor Statistics 2014).

7.2.1 Specific investment costs range for small hydropower

Figure 28 summarizes a couple of studies that have analyzed total installed costs for hydropower. Figure 28 shows that the *minimum* installed costs varies between approx. 600USD₂₀₁₀/kW – 1100USD₂₀₁₀/kW. Converted to 2005 currency, this equals 540USD₂₀₁₀/kW – 990USD₂₀₁₀/kW. IEA ETSAP indicates a minimum of 2000USD₂₀₀₈/kW for small hydropower; converted to currency of 2005 this equals 1820USD₂₀₀₅/kW. IRENA indicates a minimum of 1300USD₂₀₁₀/kW for small hydropower; converted to 2005 currency this equals 1170USD₂₀₀₅/kW.

Of course, different assumptions are used in the studies above. Therefore, it was decided to use a (rounded) value in between and assume a *minimum* specific cost of **1000USD₂₀₀₅/kW**.

Figure 28 shows that the *maximum* installed costs varies between approx. 2000USD₂₀₁₀/kW – 6300USD₂₀₁₀/kW. Converted to 2005 currency, this equals 1800USD₂₀₁₀/kW – 5670USD₂₀₁₀/kW. IEA ETSAP indicates a maximum of 7500USD₂₀₀₈/kW for small hydropower; converted to currency of 2005 this equals 6825USD₂₀₀₅/kW. IRENA indicates a maximum of 8000USD₂₀₁₀/kW for small hydropower; converted to 2005 currency this equals 7200USD₂₀₀₅/kW.

Of course, different assumptions are used in the studies above. Therefore, it was decided to use a (rounded) value in between and assume a *maximum* specific cost of **7000USD₂₀₀₅/kW**.

7.2.2 Specific investment costs range for large hydropower

Figure 28 shows that the *minimum* installed costs varies between approx. 600USD₂₀₁₀/kW – 1100USD₂₀₁₀/kW. Converted to 2005 currency, this equals 540USD₂₀₁₀/kW – 990USD₂₀₁₀/kW. IEA ETSAP, indicates a minimum of 1750USD₂₀₀₈/kW for large hydropower; converted to currency of 2005 this equals 1593USD₂₀₀₅/kW. IRENA, indicates a minimum of 1050USD₂₀₁₀/kW for large hydropower; converted to 2005 currency this equals 945USD₂₀₀₅/kW.

Of course, different assumptions are used in the studies above. Therefore, it was decided to use a (rounded) value in between and assume a *minimum* specific cost of **1000USD₂₀₀₅/kW**.

Figure 28 shows that the *maximum* installed costs varies between approx. 2000USD₂₀₁₀/kW – 6300USD₂₀₁₀/kW. Converted to 2005 currency, this equals 1800USD₂₀₁₀/kW – 5670USD₂₀₁₀/kW. IEA ETSAP indicates a maximum of 6250USD₂₀₀₈/kW for large hydropower; converted to currency of 2005 this equals 5625USD₂₀₀₅/kW. IRENA indicates a maximum of 7650USD₂₀₁₀/kW for large hydropower; converted to 2005 currency this equals 6885USD₂₀₀₅/kW.

Of course, different assumptions are used in the studies above. However for large hydropower, the maximum specific investment costs are assumed lower than the values above. Reason for this is that a large comprehensive cost analysis of over 2 155 potential hydropower projects in the United States totaling 43 GW identified an average capital cost of USD 1 650/kW, with 90 % of projects having costs below USD 3 350/kW (IRENA 2012). In another study by Lako et al. 250 projects worldwide with a total capacity of 202 GW had an average investment cost of USD 1000/kW and 90 % had costs of USD

1 700/kW or less (Lako et al. 2003). Furthermore, the Special Report of Renewable Energy gives a realistic cost range between 1000-3000USD₂₀₀₅/kW) (IPCC SRREN 2012).

It was decided to use the range in the SRREN and assume a *maximum* specific cost of **3000USD₂₀₀₅/kW**.

7.3 Interpolation method to estimate specific investment costs in a cell

At the coarse resolution we are working on, it is not possible to calculate specific investment costs for individual dams very accurately. Instead we try to prioritize the sites that are most suitable for hydropower development based on the most important characteristics of the area around them. In order for a site to be relatively more suitable for hydro development compared to another site, the area should have:

- A relatively high relief, including large local elevation differences where a dam could be constructed.
- A high river discharge.
- A high dam head, which realization is influenced by the relief at the site.
- A high riverbed slope lowers the amount of inundation needed to create a well sized reservoir.

Oak Ridge Laboratory prioritizes the suitable locations for hydropower based on a measure for the energy intensity: $energy = head \times slope \times flow$ (ORNL 2013b). The higher the value, the more suitable the location is to develop hydropower. We argue that this conceptual idea of energy intensity to prioritize specific locations could also be applied in this study on half degree resolution. Instead of the energy intensity, the technical potential in a cell is used. In this way cells with a high technical potential become preferred locations. This preference is expressed in the form of relatively low investment costs compared to other sites. It is assumed that in cells with higher potential, the specific investments costs are lower. The reason is that in cells of relatively high technical potential, it is likely to find higher elevation differences and thus more suitable locations to construct a high head dam with large capacity. It is generally found that higher dams with more capacity have lower investments costs as can be observed in Figure 27. Figure 27 shows an exponential decrease in costs when the capacity and the head increase.

In order to relate the technical potential in a cell to the specific investments costs, the cell values are sorted from low to high. The (nonzero) values of technical potential per cell are shown in **Figure 29**. The cells are divided into five categories based on technical potential. For each cell a cost factors is defined (see Table 10). The exact value of the cost factor is obtained through linear interpolation in the corresponding cost factor range.

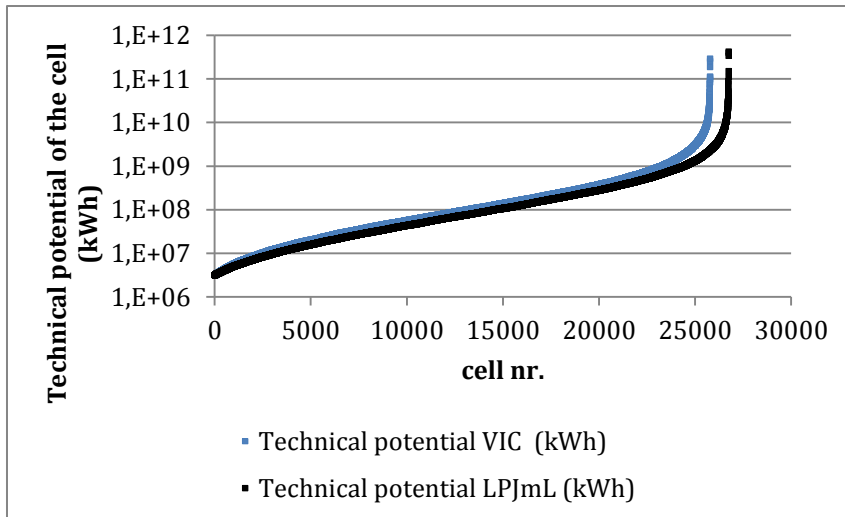


Figure 29: Technical potential in each cell, sorted from low to high.

Table 10: Cost factors to estimate specific investment costs in a cell.

Technical potential range (kWh)	Cost factor (range)
< 10 ⁷	0.8 - 1
10 ⁷ - 10 ⁸	0.6 - 0.8
10 ⁸ - 10 ⁹	0.4 - 0.6
10 ⁹ - 10 ¹⁰	0.2 - 0.4
> 10 ¹⁰	0 - 0.2

The cost factor is used to calculate the specific investment costs in a half degree cell. The specific investment costs in a cell are calculated with:

$$\text{Specific investment costs} = (\text{Spec. Inv}_{max} - \text{Spec. Inv}_{min}) * \text{Cost factor} + \text{Spec. Inv}_{min} \quad (7.2)$$

Whereby *Spec.Inv.max* is the maximum of the costs range and *Spec.Inv.min* is the minimum of the cost range.

7.4 Capacity factor based on design flow and efficiency

Hydropower plants don't operate the entire year. The operating time is influenced by the natural variation in river flow, supply and demand characteristics ("peak" or "off peak" supply), characteristics of the plant itself (the "design flow and "installed capacity") and maintenance hours. Supply and demand computations are made in TIMER. Maintenance hours are assumed negligible when considering an availability of 98% (IEA ETSAP 2010).

Hydropower plants are mainly designed for a site specific discharge regime. In the design phase of the project, the size of the turbine is based on the so-called design flow (ORNL 2013a). The design flow can be determined using a flow-duration curve based on flow measurements on a daily, weekly or even monthly time scale (ORNL 2013a). A monthly flow duration curve is constructed by sorting all measured discharges from high to low and to calculate the percentage of time that each daily average flow is exceeded. The flow duration curve in Figure 30 shows the amount of time per month that a specific discharge is exceeded at the site. It can be reasoned that the hydropower plant should

not be designed to be able to capture the maximum discharge of a river, since this would imply that the hydropower plant would operate less (full load) hours in a year than would be economically optimal. Thus, an economic optimum capacity of a hydropower plant exists, determined by a flow-duration curve.

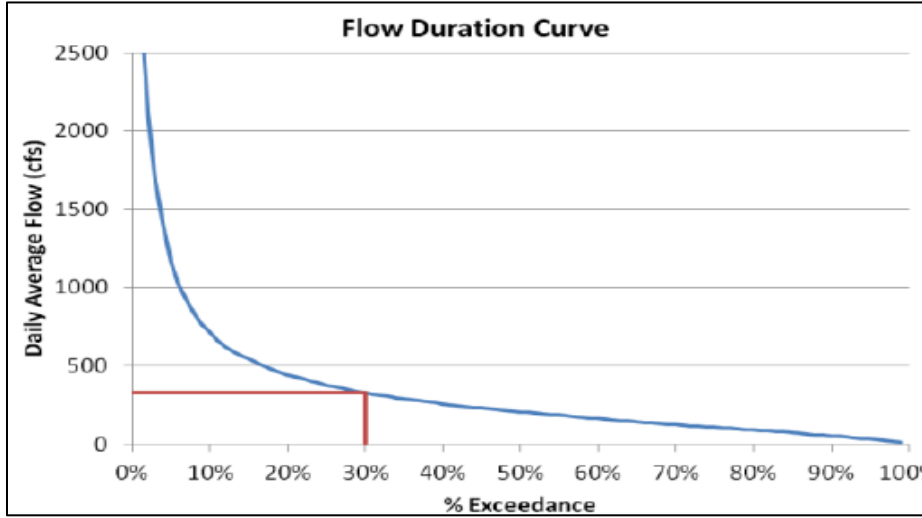


Figure 30: Example of a flow duration curve for one USGS stream gauge (ORNL 2013a).

In a study of undeveloped hydropower in the USA, Oakridgale laboratory uses the design flow (Q_{design}) at a discharge level of 30% exceedance (see Figure 30).

In this study on global scale, it was decided to apply the discharge data from VIC and LPJmL to estimate the design flow. It was chosen to use the 4th highest mean monthly annual discharge over the period 1970-2000 as an estimate of the design flow in a cell. With this choice of design flow, the discharge will on average be exceeded about three 3 months of the 12 months in a year; in other words 25% of the time per year. The maximum amount of generation in a cell is then equal to:

$$P_{max,cell} = \rho g Q_{design,cell} \Delta h \cdot \eta_{w2w} = \rho g Q_{4th-highest,cell} \Delta h \cdot \eta_{w2w} \quad (7.3)$$

In which a water-to-wire efficiency (η_{w2w}) of 70% is assumed (Craig et al. 2010). We assume a lower efficiency to account for lower off-peak efficiencies and to account for lower productivity when the design flow is exceeded.

The annual average generation at each site is calculated using the average flow and the *TTR* as explained in chapter 6.1. This gives:

$$P_{actual,cell} = \rho g Q_{annual_mean} \Delta h \cdot TTR \quad (7.4)$$

The capacity factor is equal to the proportion of energy that is produced compared to the amount of energy that could be produced at full operating time (Blok 2007; ORNL 2013a). In this case, this is calculated as an annual average between the years 1970 and 2000.

Using the equations above, this gives:

$$Capacityfactor(\%) = \frac{P_{actual,cell}}{P_{max,cell}} = \frac{\rho g Q_{mean_annual} \Delta h \cdot TTR}{\rho g Q_{design} \Delta h \cdot \eta_{w2w}} = \frac{Q_{mean_annual} \cdot TTR}{Q_{4th-highest-month} \cdot \eta_{w2w}} \quad (7.5)$$

When calculating the capacity factors in each cell using the discharge of both the VIC and LPJmL models, it ends up in a range between 20% - 90% and with an global average of about 45% for both models, see Figure 31 and Figure 32. The differences in the graphs are directly explained by differences in the discharge regime, that is: mean annual flow compared to the fourth highest monthly flow.

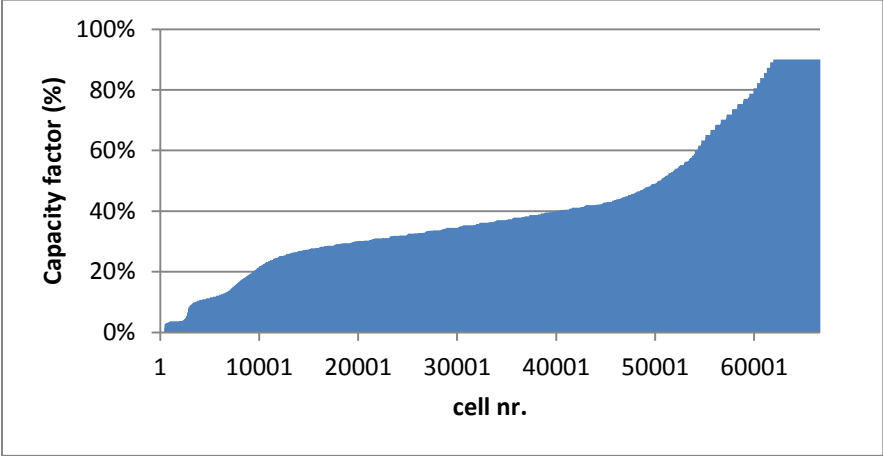


Figure 31: Capacity factor per cell for VIC data. Average: 41%.

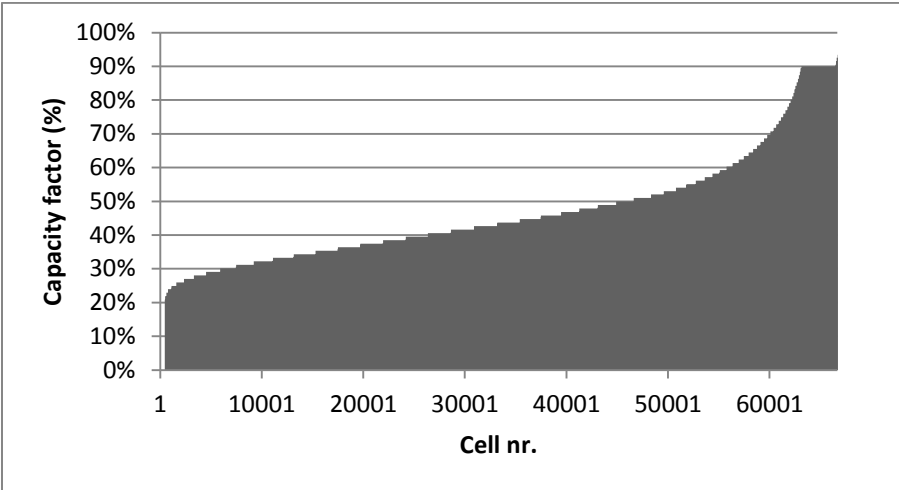


Figure 32: Capacity factor per cell for LPJmL data. Average: 47%.

We can easily compare the average load factor to the literature. Using the installed global capacity and annual generation given in the International Journal of Hydropower and Dams, I calculate a global average capacity factor of 41.5%.

7.5 Calculation of the LCOE

The technological assumptions to compute the LCOE can be viewed in Table 11.

Table 11: Technological assumptions used to calculate the LCOE.

Technological Assumptions			
Type of plant	Run-of-river	Dam and reservoir	Source:
Technical potential in the cell (MW)	1-10 MW	> 10 MW	Based on classification of small hydropower by (WSHPDR 2013)
Mean annual discharge in the cell (m³/s)	At least 0.1m ³ /s	> 200m ³ /s	(Monk et al. 2009)
Difference between mean and minimum elevation on the river network in the cell (m)	At least 15m	At least 15m	Based on an elevation difference of 15 between cells (Fekete et al. 2010). For run-of-river, this is an assumption.
Specific investment cost range (\$₂₀₀₅/kW)	1000-7000 \$ ₂₀₀₅ /kW	1000-3000 \$ ₂₀₀₅ /kW	Estimated cost-range, reasoning explained in this chapter.
Discount rate (%)	10%	10%	Frequently used by (IEA ETSAP 2010) (IRENA 2012)
Economic lifetime (years)	40	60	Average rounded figures based on (IRENA 2012)
Operation & maintenance costs (% of investment per year)	2%	2%	Average rounded figures based on (IRENA 2012)

7.6 Regional cost-supply curves

In this paragraph, regional cost-supply curves for hydropower are presented. The curves are calculated using the technical potential and the LCOE per cell and aggregating this to a region. Only cost supply curves for VIC data are given in this paragraph. LPJmL cost supply curves are given in appendix 5.

Figure 33 gives an impression of the overall results. In general, all curves increase slowly in costs in the beginning of the curve and thereafter the slope of the curve increases more rapidly. China has the largest technical potential followed by Rest of South America, Brazil, USA, West Africa etc. Production costs for Russia and West Africa are very low in the beginning of the curve, which indicates favorable conditions for hydropower. Overall, the costs are in the range of 4-22 \$ct/kWh.

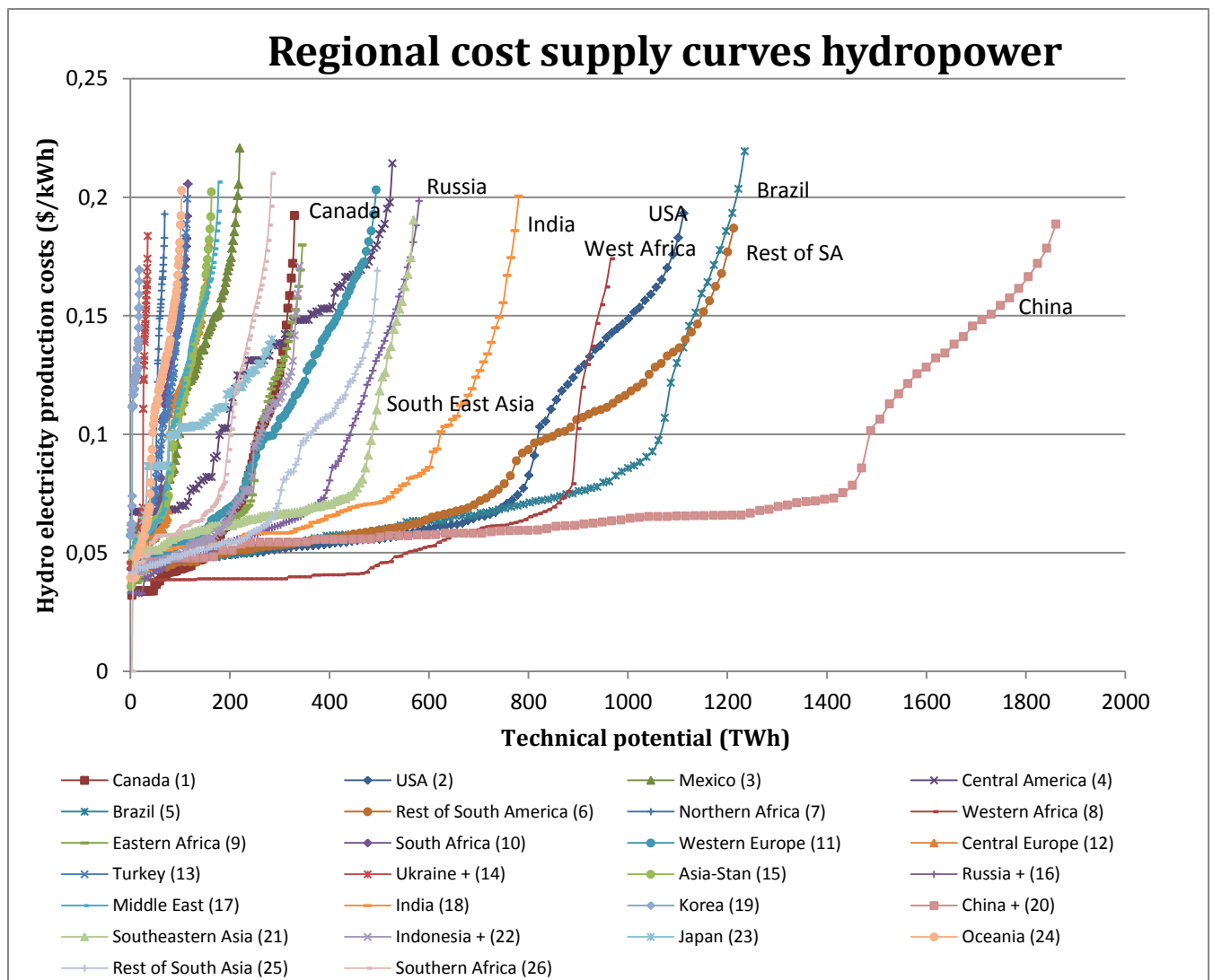


Figure 33: Regional cost supply curves for hydropower. Based on method C for theoretical potential using VIC data and the 10th percentile elevation. A TTR of 0.364 per region was assumed. Costs calculations are explained in chapter 7.

Figure 34 until Figure 39 shows the curves for a selection of large IMAGE regions.

The following data points are plotted in the graphs (when available).

- Production in 2011 according to IJHD.
- Production in 1970, 2014 and 2100 according to TIMER scenarios.
- The technical and economic potential from literature (GEA, 2012; IJHD, 2013).
- Production according to BlueMAP scenarios (IEA 2010b).
- A maximum competitive price level of 8\$/kWh according to GEA (GEA, 2012).

From the different figures, the following can be observed:

- China has not reached its economic potential and can expand production against competitive price levels for the next decades.
- South America has not reached its technical potential and can expand production against competitive price levels for the next decades.

- USA has not reached its economic potential and can expand production against competitive price levels for the next decades.
- Canada has already got to the point where it can expand production no further. The production is almost equal to the technical potential.
- Both India and Russia have not reached their economic or technical potential and can expand production against competitive price levels for the next decades.
- All African regions have not reached their economic or technical potential and can expand production against competitive price levels for the next decades. Especially West Africa has a high potential that could be used against low costs.
- West Europe already had a large fraction of potential utilised in 1970. Now West Europe has almost got to the point where it can expand production no further. The technical potential is also underestimated compared to literature.
- In Central Europe production started later than in West Europe. Central Europe has not reached its technical potential and can expand production against competitive price levels for the next decades.

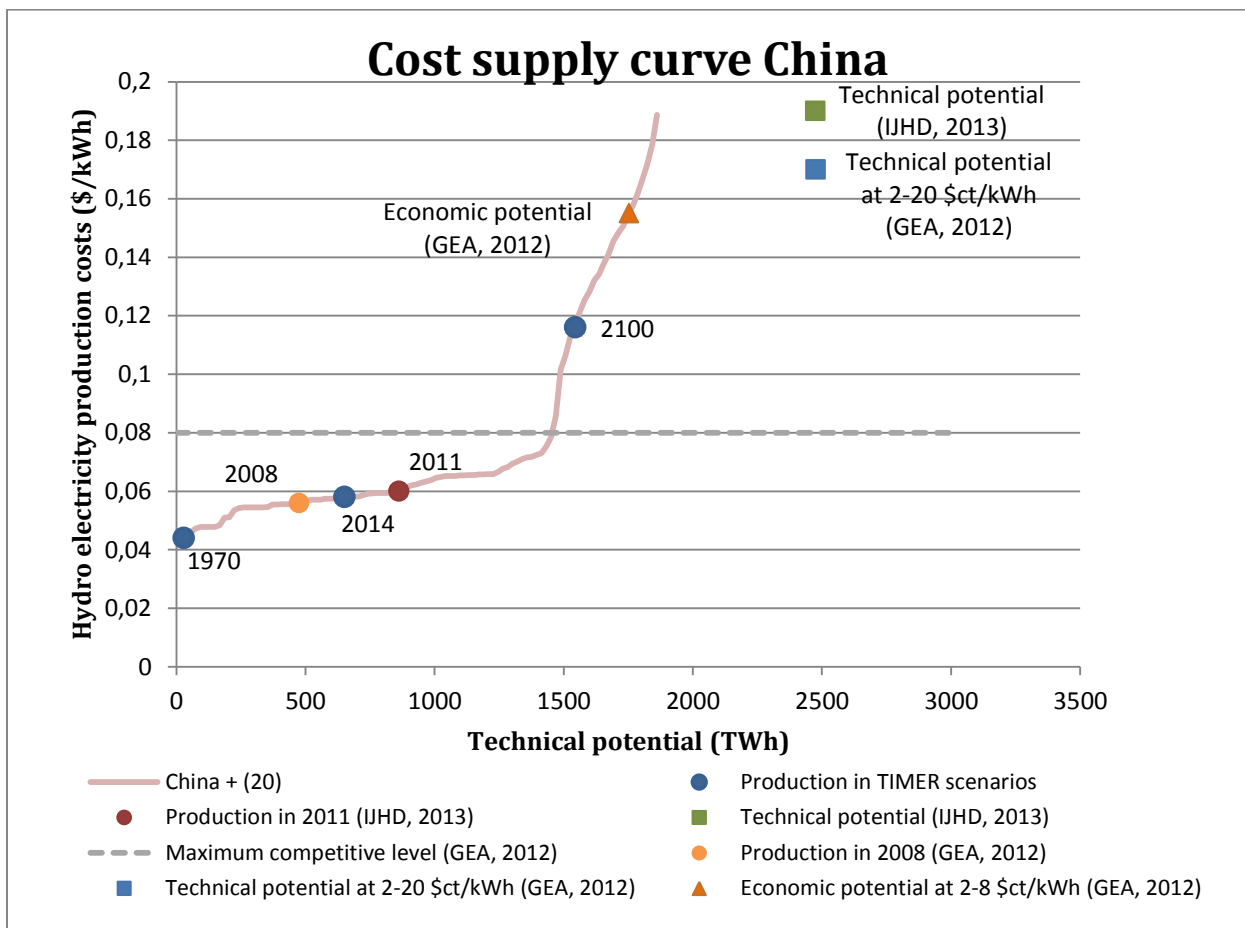


Figure 34: Cost supply curve for China (based on VIC data)

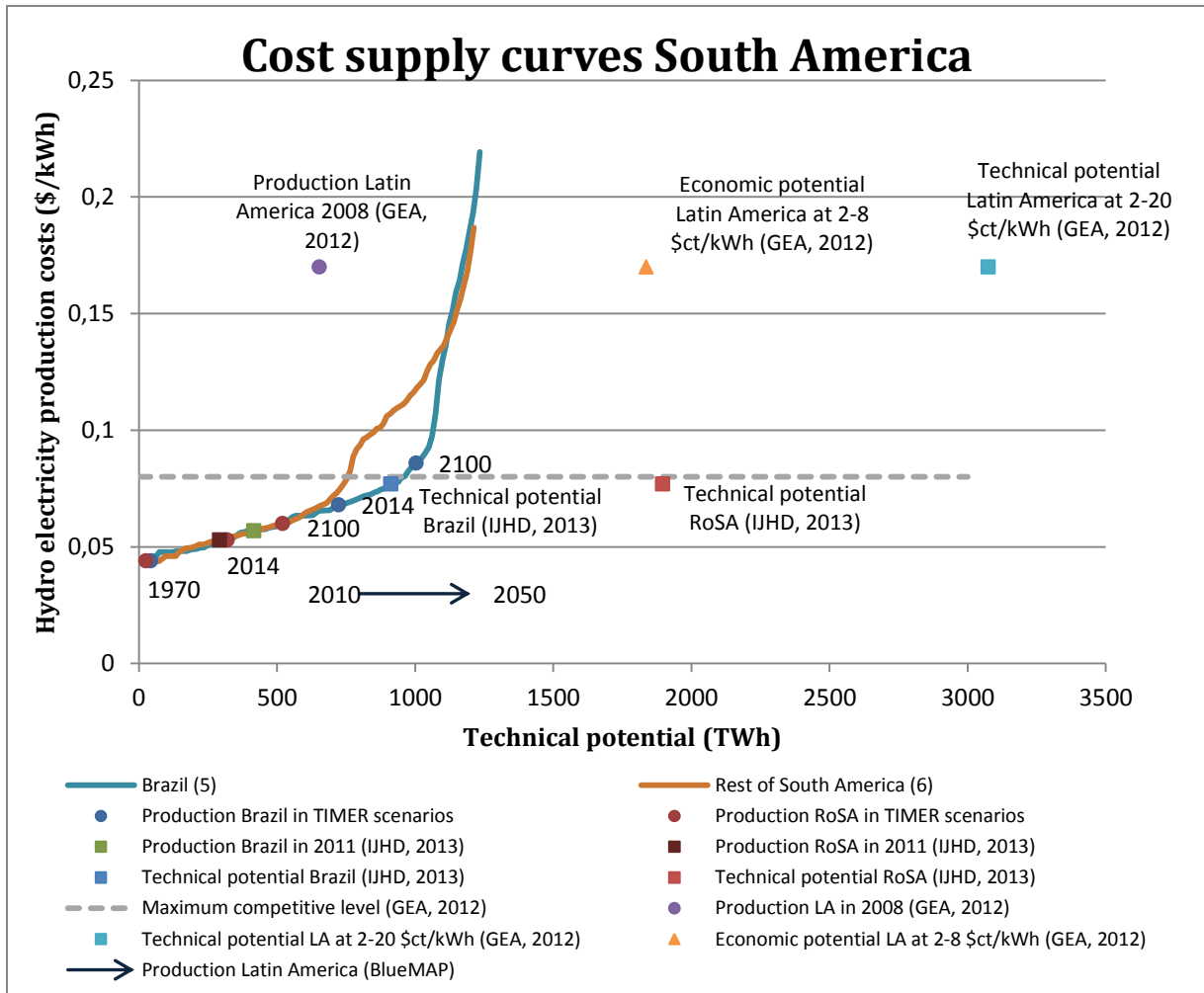


Figure 35: Cost supply curves for South America (based on VIC data).

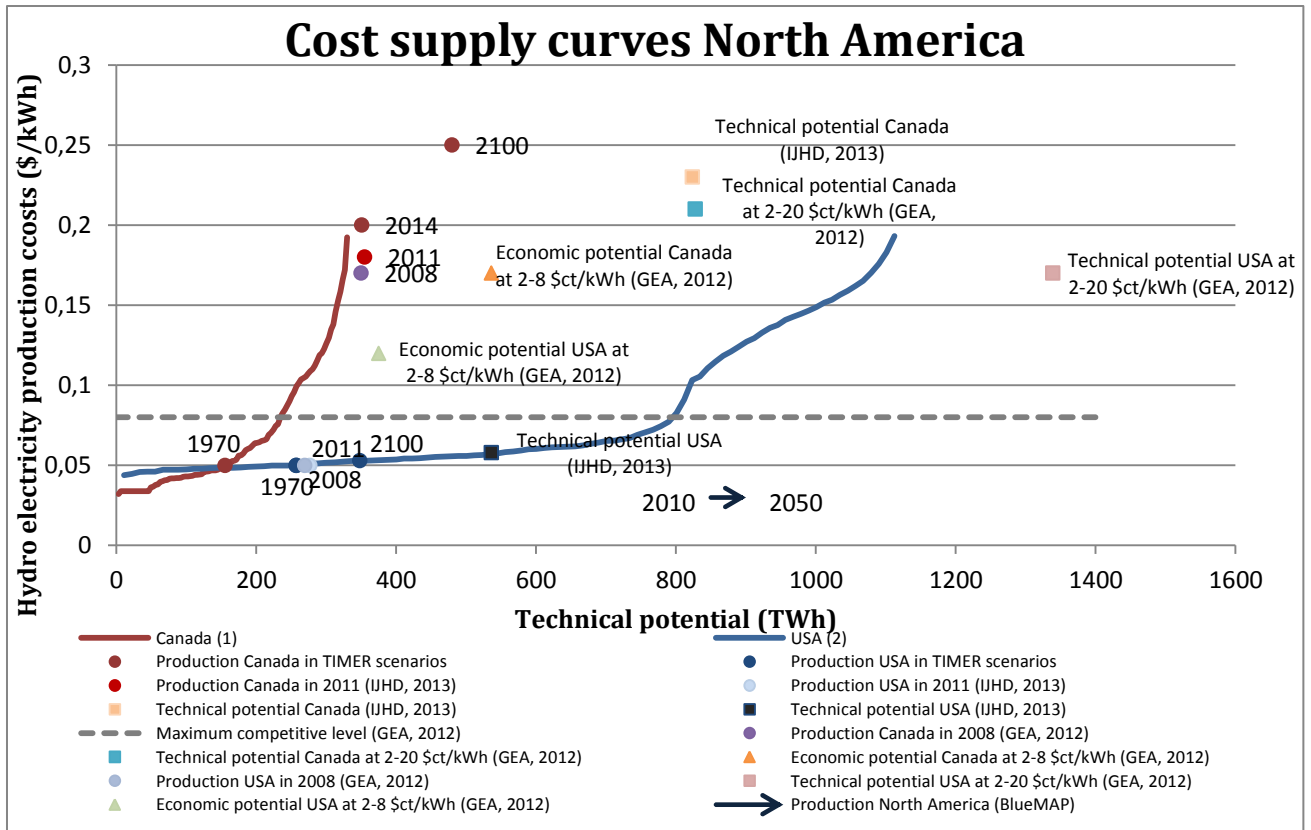


Figure 36: Cost supply curves for North America (based on VIC data).

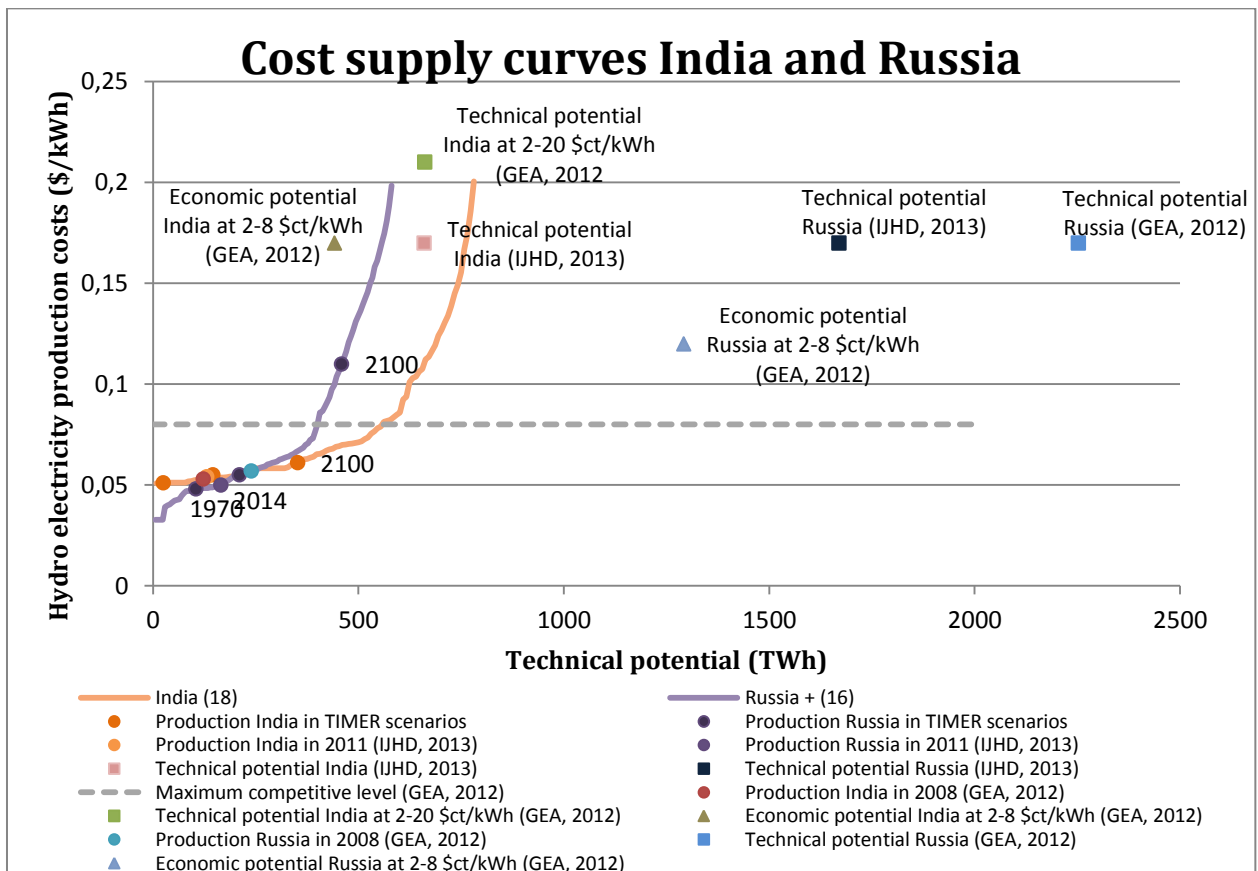


Figure 37: Cost supply curves for India and Russia (based on VIC data).

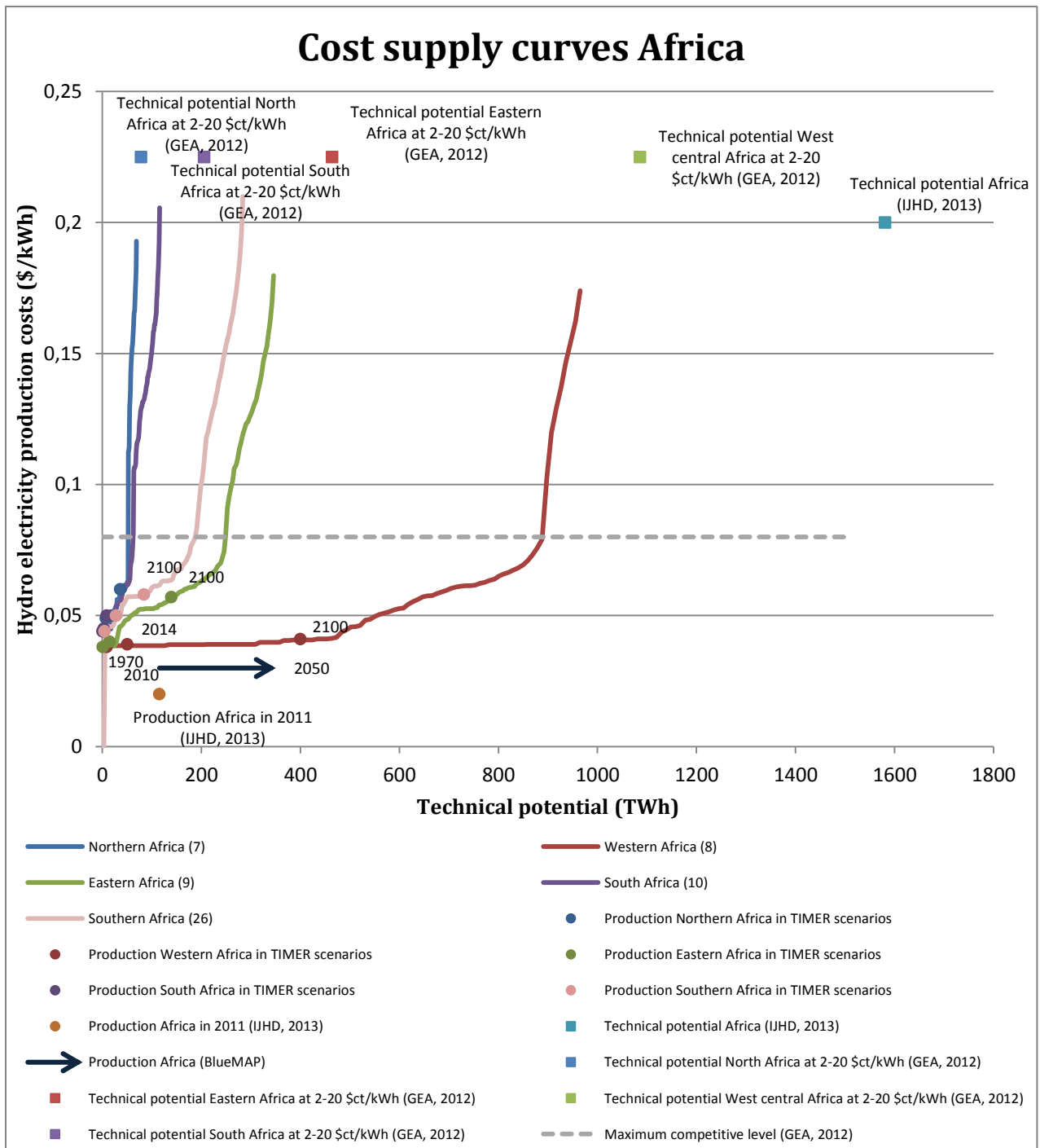


Figure 38: Cost supply curves for Africa (based on VIC data).

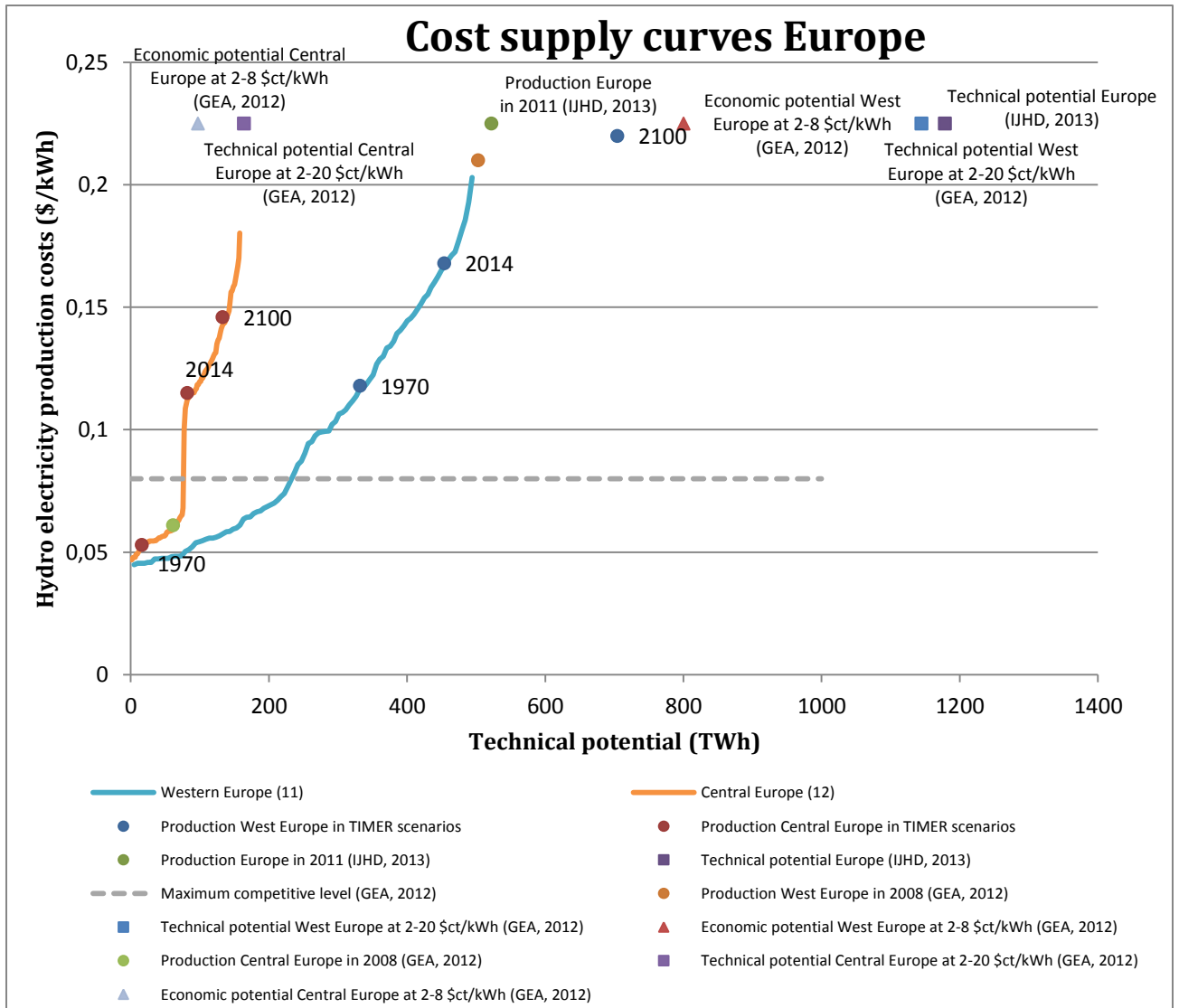


Figure 39: Cost supply curves for Europe (based on VIC data).

8. Discussion

8.1 Uncertainties in the assessment methods of Hydropower potential

As seen earlier, the global theoretical potential for hydropower has been estimated several times in the literature by using different approaches yielding significant different results.

Fekete et al. (2010) describes that in theory the theoretical potential can be calculated by considering all global river reaches (i.e. length of a river between two points) and calculating the integral of mean annual discharge Q (m^3/s) x riverbed slope S (m km^{-1}) x density of water ρ (1000 kg m^{-3}) x gravitational acceleration (m s^{-2}) over the length of all river reaches dl (km). In formula form, this is:

$$P_{th} = \int_0^L \rho g Q S dl \quad (8.1)$$

Using equation (8.1) requires detailed information on both riverbed slope and discharge along all river reaches. This equation is recommended to use, however data on these variables was not available on a global scale.

Even more sophisticated methods are described in literature, whereby complex GIS-functions are applied to calculate theoretical potential of streams using hydrology formulas (Monk et al. 2009; Punys et al. 2011). However, these GIS methods are not used yet on a global scale, but mainly for smaller regions or countries. This is also caused by lack of global available high resolution data on elevations and river discharge.

It's interesting to explore how advanced the methods can become for calculating hydro potentials. Still every method is subject to errors in the input data. The combination of uncertainties in a DEM and a discharge dataset leads to higher uncertainties in the annual mean theoretical hydropower potential. The DEM doesn't always represent the actual elevation of the river. Additionally, the discharge is provided by hydrological models having their associated uncertainties about climatological input data. Therefore it is not necessarily better to use a very high resolution analysis. It depends on the purpose of the research. For global studies like this one, half degree data is considered reasonable.

8.2 Issues with hydropower survey data

Resource potential assessments for hydropower have currently been different to those used for other renewables. For renewable sources such as wind or solar, potentials are assessed by beginning with a theoretical estimate, which is then reduced by the application of constraints, to a technical potential, which is further reduced to an economical potential. In general, hydropower potential is assessed by adding up the potential of well-known sites, and many other sites are omitted for different kinds of reasons. As a consequence of this the theoretical potential is underestimated (GEA, 2012).

For example, the US Rocky Mountains are considered non-suitable even though they are similar to the Alps, where large developments have happened (GEA, 2012). Smaller sites, as well as existing dams not used for hydropower, also were not considered in the United States until recently (GEA, 2012). This might very well be the explanation that this research overestimated the technical potential of the USA.

As a result of social and environmental constraints, it can be assumed that not all economic potential can be developed. It is important, however, that all these potentials are still included in the theoretical and technical potential. This is because climate change, new environmental policies, changed social preferences, and new technologies, especially for transmission, can make remote sites accessible, affect energy supply preferences and demand levels, and lead to a reassessment of previously excluded hydropower locations (GEA, 2012). The assessment and reassessment of hydropower sites is a costly affair (GEA, 2012). Thus in many countries, where many well-known sites still have to be assessed. This could be the reason for the low theoretical potential of Africa in the survey data compared to the GIS calculations on hydropower potential.

8.3 Geographical potential

Using the minimum population constraint in the geographical potential step leads to exclusion of a lot of cells in Canada and Russia. This is a likely explanation for the deviation compared to the survey data from IJHD. These unpopulated sites could be included when a constraint is introduced to only build small hydropower plants at these areas. Alternatively, by adding transportation costs for these areas could increase the costs and place these areas on the upper-right side of the cost-supply curve.

The higher potential in the USA could be explained by the inclusion of the Rocky Mountains (see 8.2).

8.4 Technical and economic potential

The technical to theoretical ratio (TTR) was important in calculating the technical potential. The value is taken as a constant for each region but this might be a simplistic approach. It was considered to apply regional TTR values or values on the country level. However, while the technical potential might be estimated with more precision, it leads to other costs as the capacity factor is changed. The USA would have much lower capacity factors (about factor 3) and Russia would gain much higher capacity factors (about factor 2). It was found that the LCOE for US hydro power plant isn't higher than in other regions (IEA 2010a).

To construct large hydropower plants, it should be possible to construct a sufficiently sized reservoir on the site. The dimensions of reservoirs are not taken into account in this study. Basically it was assumed that if the site potential is sufficient, a reservoir could be constructed. However, this may not be always the case as it depends on the topology. Fekete et al. indicates that the reservoir capacity had to be $> 0.5 \text{ km}^3$ for large hydropower (Fekete, 2010) and estimates reservoir sizes for hydropower. Taking a more in-depth look into this matter may provide better results.

8.4.1 LCOE

Investment costs for hydropower are very site specific. Therefore the estimates here can't be interpreted on the individual cell level. Costs differences have to be interpreted only for a large region. On regional level in this study, differences in LCOE reflect the differences in technical potential and discharge regimes. This is because the technical potential in a cell determined the specific investment costs and the capacity factor in a cell is determined with the design flow.

A difficult aspect of cost estimations is that the capacity for which the costs are given varies from small units of 0.3MW to large dams of 18GW (in China). The capacity factor of hydropower plants are also different, between 29-80% (IEA & NEA 2010). A total cost range exists for hydropower exists between 757USD/kW – 19330 USD/kW (IEA & NEA 2010). As seen in Chapter 7 the maximum for small and large hydro were established at 1000 and 7000 \$/kW respectively. Thus, hydropower plants of higher investments costs are not represented.

8.4.2 Multipurpose Dams

Hydropower Dams may be designed for electricity generation alone, or for multiple purposes. Multipurpose projects typically have significant reservoir capacity and could provide services such as irrigation, freshwater supply, flood control, and recreation. These other uses may affect the volume of water that is available for electricity production. GEA indicates that 30–40% of world irrigation is supplied by reservoirs (GEA, 2012). When this is not taken into account, it can distort the assessments of the economic potential of hydropower for energy purposes (GEA, 2012).

9. Conclusion

The aim of the research was to determine the regional potential for hydropower and the cost levels at which that potential could be exploited. This was done through the construction of cost supply curves for 26 IMAGE world regions. During the process steps to construct cost supply curves different intermediate results were obtained.

Observing the results, the following conclusions are drawn, indicated as key points in **bold**, each with a short explanation.

When calculating the theoretical potential, a wide range of global potentials was obtained between 6-21TW. The calculated estimates seem high compared to survey data. Some of the more realistic methods come close to estimates seen in survey data.

We observe from the calculations on the theoretical potential that a wide range of global theoretical potentials was obtained by choosing different methods to calculate elevation differences. Also the choice of hydrological model to simulate the global discharge was playing an important role in determining the hydropower potential. We further observe that assuming a lower elevation for the river in the DEM (i.e. 10th percentile elevation) gives results that come closer to values seen in literature. This indicates that the main fraction of river discharge is located on the lower half of elevations in the landscape.

Determining the theoretical potential using equations leads to an overestimation compared to country survey data on hydropower.

Survey data only includes data on hydropower potential that is well known or documented. Some countries are not reported that well or completely in these journals. Also, some sites are not included. For these reasons, GIS assessments are likely to result in higher estimates.

The observation that the modelled potentials for African regions are much higher compared to IJHD is an indication that African country surveys are not as complete as those of other countries.

It can be viewed in IJHD that country data for Africa is frequently missing. But observing the difference between the calculated potential and the reported values in IJHD gives reasons to assume that African country surveys are not as complete as those of other countries.

The largest technical potentials are found in respectively China, Brazil and Rest of South America. West-Africa also has a high potential.

This can be viewed in the technical potential result section. This result is in accordance with IJHD survey data.

The cost supply curves seem reasonable at representing most of the large regions. In some of the smaller regions correction factors for the technical potential were used.

Lots of production points lay on realistic positions on the curves. Although some technical potentials are overestimated and some are underestimated compared to IJHD survey data. The reasons for this are different per region (as seen in Discussion). Some smaller regions (Japan, Central America and Europe) had to be corrected to bring the technical potential in range of production as reported in literature.

From the cost supply curves, the following main points can be concluded.

- China, India, Russia and the USA have not reached their economic potential and can expand production against competitive price levels for the next decades.
- South America has not reached its technical potential and can expand production against competitive price levels for the next decades.
- Canada has reached the point where it can expand production no further. The production is close to the technical potential.
- All African regions have not reached their economic or technical potential and can expand production against competitive price levels for the next decades. Especially West Africa has a high potential that could be utilised at low costs.
- West Europe already had a large fraction of potential utilised in 1970. Now West Europe has almost got to the point where it can expand production no further.
- Central Europe has not reached its technical potential and can expand production against competitive price levels for the next decades.

10. Suggestions for further research

Based on the results and the uncertainties in the outcomes, the following suggestions for further research are given:

- In the theoretical potential, try to correct method C for cells of negative potential. To do this, a flow direction map is required that is consistent for use with the HydroSHEDS conditioned DEM.
- Consider the influence of climate change on river discharge. Consider a modelling of discharge in VIC or LPJmL without climate change (implying no change in discharge) and a run with climate change (implying less discharge causing a lower hydro potential). Use the different discharge maps to estimate the hydropower potential under different scenarios and examine the effect on the cost supply curves.
- Using a minimum population constraint in the geographical potential step leads to exclusion of a lot of cells in Canada and Russia. These unpopulated sites could be included when a constraint is introduced to only build small hydropower at these areas. Alternatively, adding transportation costs for these areas could increase the costs and place these areas on the right side of the cost-supply curve.
- In this research, specific investment costs are allocated to grid cells of half degree based on their relative technical potential. It can be easily reasoned that other factors also play a role in determining the specific investment costs. One could think of the geographical location, e.g. a dam located in a (rain) forest) or a dam on very high altitude. It might be interesting to include the effects of this on the costs.
- One of the assumptions in this research is that the discount rate and economic lifetime are the same for every type of plant technology in every region. One could argue that it is more realistic to distinguish regions from each other by using different figures. For example, the discount rate can be made dependent on the regional income level. For lower income countries, the discount rate would then be higher since present day investments are preferred more compared to high income countries.

- More validation on the cost supply curves could be done by comparing them to empirical data on production for existing dams and associated generation costs. Basically, a cost-supply curve can be made based on existing dam data. For instance, Lako (2003) already constructed cost-supply curves on a regional basis using empirical data but did not estimate the generation costs (i.e. \$/kWh).
- Include the obtained regional cost- supply curves in this thesis in TIMER. A (baseline) scenario can be run in TIMER and the development of hydropower can be compared to the current (exogenous) representation of hydropower in TIMER. The next step might be to use data on existing dams to validate the hydropower capacity calculation of TIMER. This means that the installed capacity is compared to the modelled capacity in TIMER.

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14. List of abbreviations

DEM	Digital elevation model
GW(h)	Gigawatt (hour)
IEA	International Energy Agency
IMAGE	Integrated Model to Assess the Global Environment
IRENA	International Renewable Energy Agency
IJHD	International Journal of Hydropower and Dams
kW(h)	Kilowatt (hour)
LCOE	Levelized costs of energy
LPJmL	Lund-Potsdam-Jena managed Land
MNL	Multinomial logit
MWh	Megawatt hour
PHS	Pumped hydro storage
TIMER	Targets IMage Energy Regional model
TW(h)	Terawatt (hour)
VIC	Variable Infiltration Capacity

Appendix 1: Hydropower in TIMER in the current situation

Currently the potential capacity from the WEC (2001) is used. The potentials are given for the 26 world regions as can be in Figure 40.

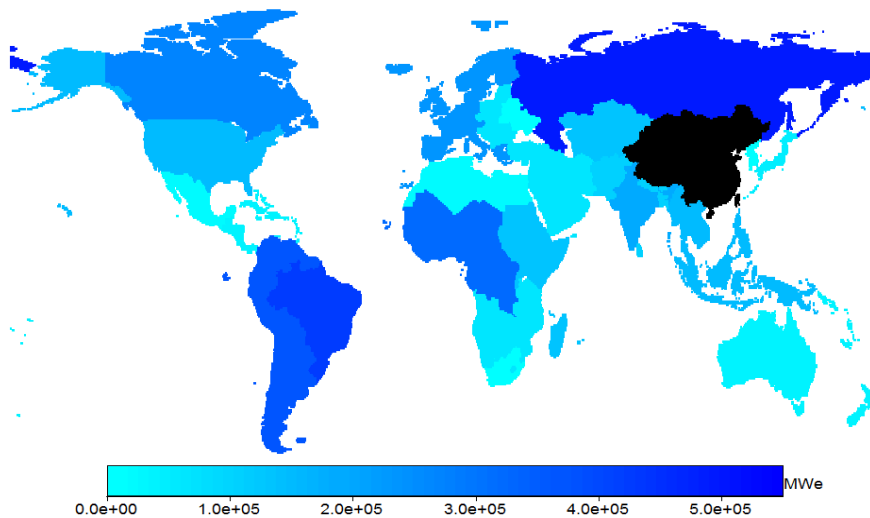


Figure 40: Potential Capacity of hydropower as used in TIMER. The regional data is used to calculate hydro electricity generation in TIMER.

With this the desired fraction of hydropower capacity is calculated for each year. This implies that the growth in the amount of generation is the same in all scenarios. The regional production for hydropower is shown in Figure 41. Hydro-electricity is increasing in all regions until 2100. On global scale, hydropower climbs to around 27,000 PJ of production in 2100. This is equal to 7500TWh.

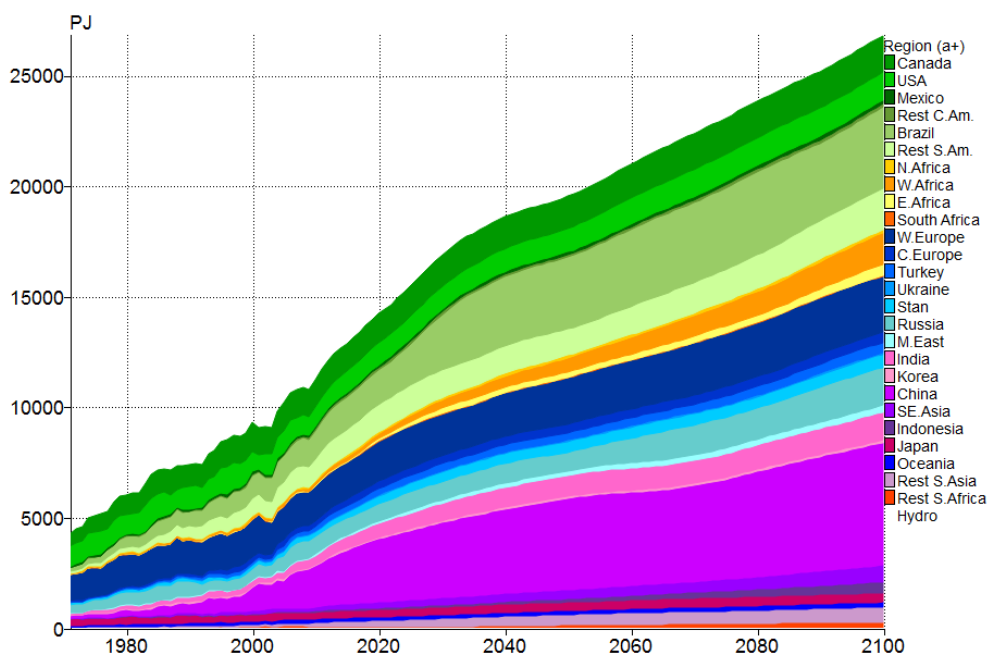


Figure 41: Regional hydro electricity production in TIMER scenarios (1970-2100).

Hydropower is part of the electricity mix in TIMER. A graph of the world electricity production between 1970 and 2100 (in scenario R3G9) is shown in Figure 42.

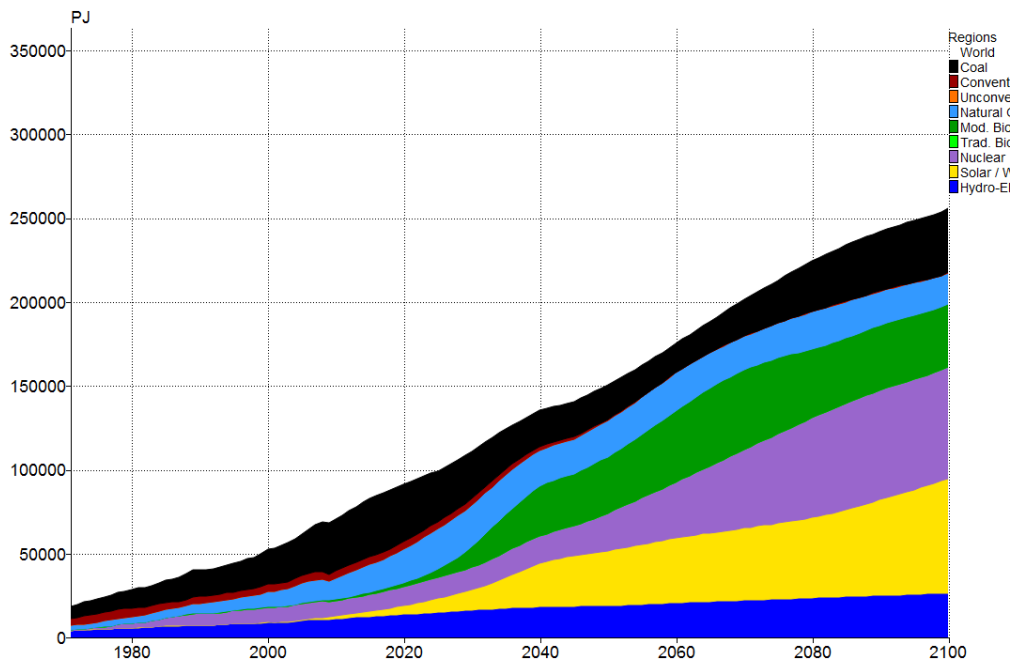


Figure 42: World electricity production as modelled in TIMER scenario R3G9.

With world production shares in Figure 43.

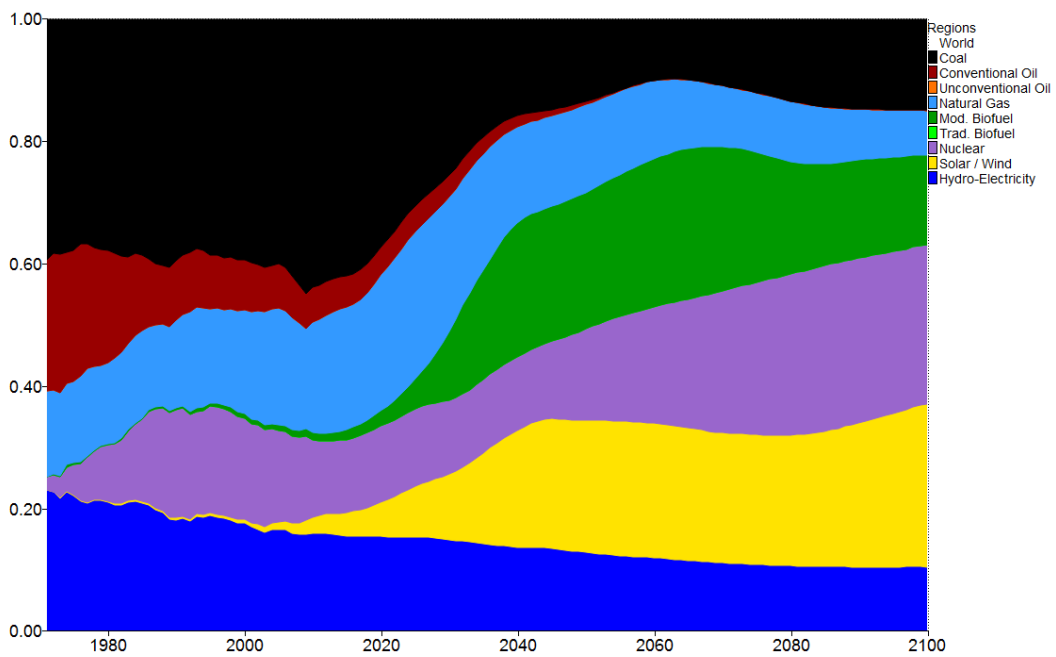


Figure 43: Electricity production shares as modelled in the TIMER R3G9 scenario. Hydropower is gradually decreasing in share.

Appendix 2: Turbine application chart

The type of turbine used depends on the flow through the penstock and head as shown in Figure 44. It can be observed that the natural river discharge and natural topology plays an important role in determining which turbine will be used during the design phase.

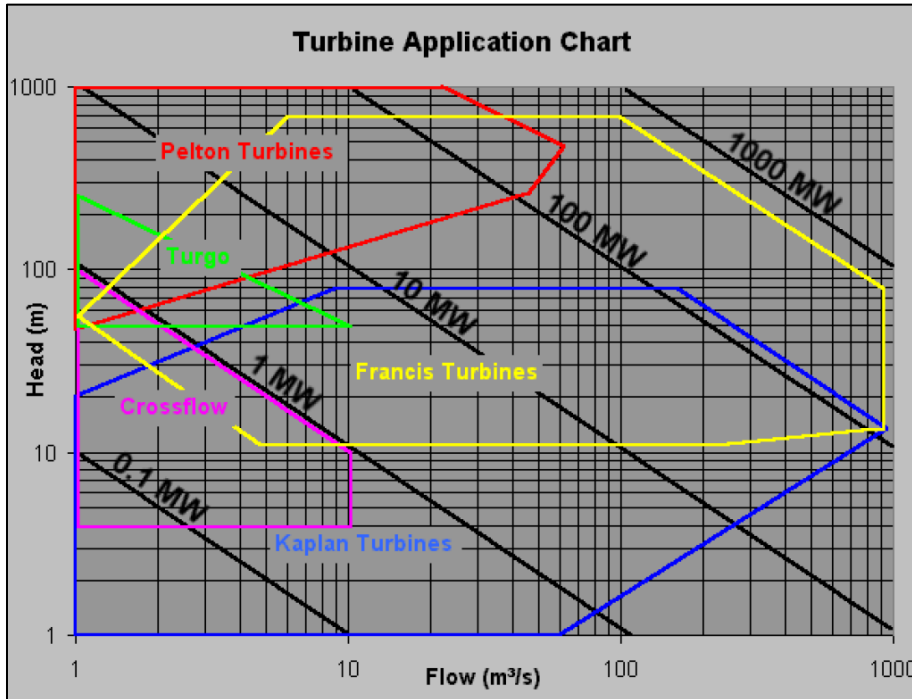


Figure 44: Turbine application chart for different hydropower turbines (Craig et al. 2010).

Appendix 3: WWF HydroSHEDS conditioned DEM

To improve on the accuracy of hydrological calculations made in this thesis, it was decided to use a hydrological conditioned DEM, namely HydroSHEDS. Figure 45 shows the spatial extent of the WWF HydroSHEDS digital elevation model on 30 arc second resolution.

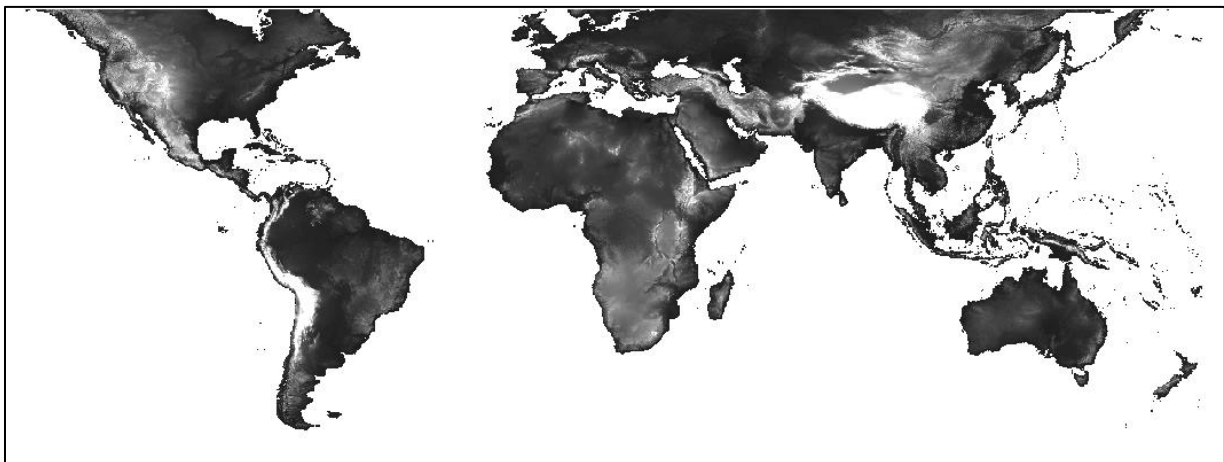


Figure 45: Spatial extent of the HydroSHEDS conditioned DEM on 30s resolution. Values above 60 degrees north are not available.

This DEM can be interpreted as an elevation model that is corrected for cells on river streams. For these cells, the river is scraped trough the landscape and the associated elevations are given on these cells This is a process called *streamburning* (WWF 2009). It appears slightly better to use this DEM compared to a conventional DEM such as GTOPO30 on full extent, however the HydroSHEDS data has no data available for latitudes above 60 degrees north. This implies that no elevation data is available for countries such as Norway, Sweden and northern Russia. Therefore, in this thesis, GTOPO30 data is merged to DEM for the remaining part of the cells above 60 degrees north. GTOPO30 is an 30 arc-second DEM derived from several raster and vector sources of topographic information covering the full spatial extent of the globe (USGS 1996).

Appendix 4: Geographical potential

In Figure 46:

- Cells with protected areas are in green
- Cells with permanent ice cover are in gray
- Cells with population above 10^7 are red
- Cells with population below 10^3 are in mango

The cells in light blue color are left when all geographical constraints are applied.

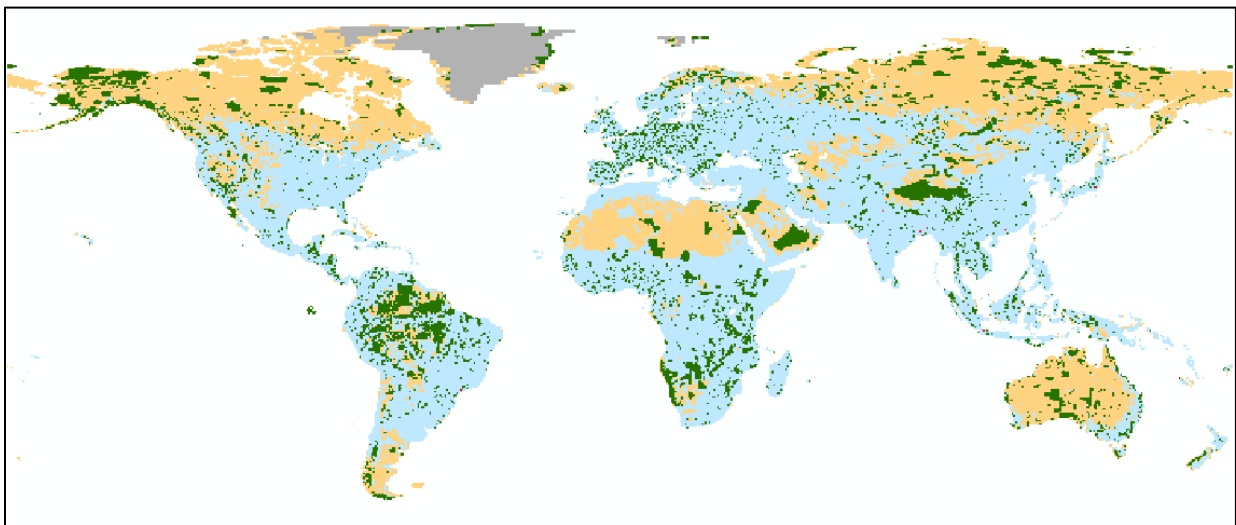


Figure 46: Map of geographical constraints for hydropower.

Appendix 5: Turbine Efficiency

The efficiency of hydropower turbines has been continuously improved over the years, see Figure 47. Modern equipment, both new and replacement turbines, reaches efficiencies of 90-95%. (EIA, 2012) Improvements made in the last 30 to 50 years will continue, although improvements can be expected to be only marginal, mainly in physical size, hydraulic efficiency and environmental performance.

An average efficiency of 85% is often seen as general estimate (Craig et al. 2010; IEA 2012). This study assumes an overall efficiency of 70% from water to wire. This efficiency is lower, due to the fact off peak efficiencies are taken into account. Also, the efficiency of small hydropower is generally lower than for large hydropower (Craig et al. 2010).

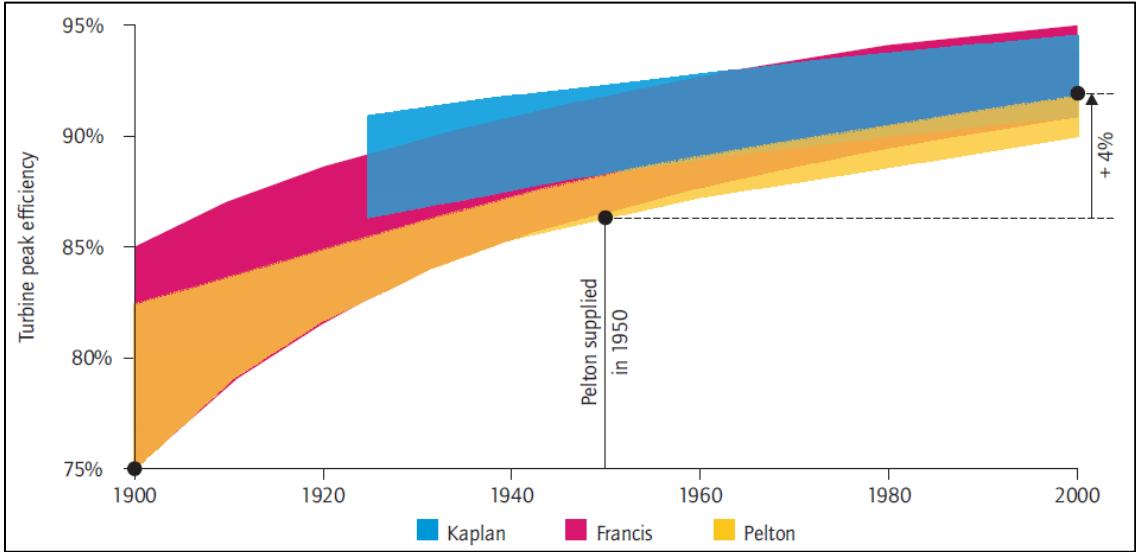


Figure 47: Improvement of hydropower generation efficiency over time (IEA 2012).

Appendix 6: Regional cost supply curves for LPJmL data

Regional cost supply curves for hydropower using LPJmL are shown in Figure 48.

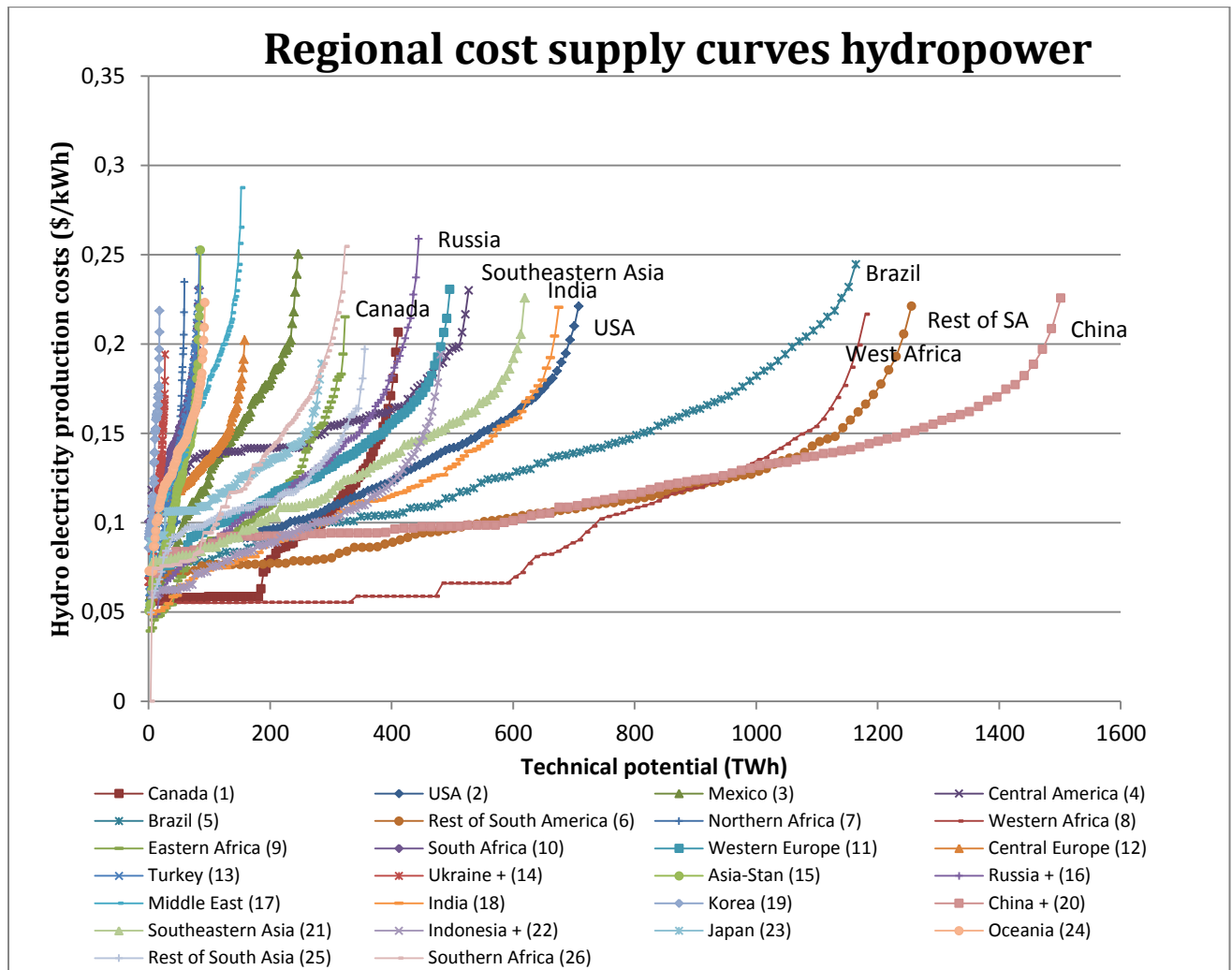


Figure 48: Regional cost supply curves for hydropower. Based on method C for theoretical potential using LPJmL data, and stn30. A TTR of 0.364 was assumed. Costs calculations are explained in chapter 7.