TECHNOLOGY CATALOGUE FOR THE ETHIOPIAN POWER SECTOR

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Ministry of Water, Irrigation and Energy

Ethiopian Electric Power

Danish Energy Agency

Ea Energy Analyses

Technology Data for the Ethiopian Power Sector

CONTENT

FOREWORD

Today, innovations and technology improvements within renewable energy are taking place at a very rapid pace. Long term energy planning is very dependent on cost and performance of future energy producing technologies. The objective of this technology catalogue is to estimate such data. Having good understanding of technologies in terms of cost and performance is a key to good energy planning.

The historical development of costs for renewable energy is illustrated in the graph below. Renewables have seen a dramatic cost decline in the past years; along with other rapidly developing technologies, well-thought future cost projections are paramount to energy modelling activities. As an example, the levelized cost of electricity (LCOE) for photovoltaic (PV) systems dropped from 0.38 $/kWh in 2010 to 0.04 $/kWh in 2022 (world average) (Figure 1).

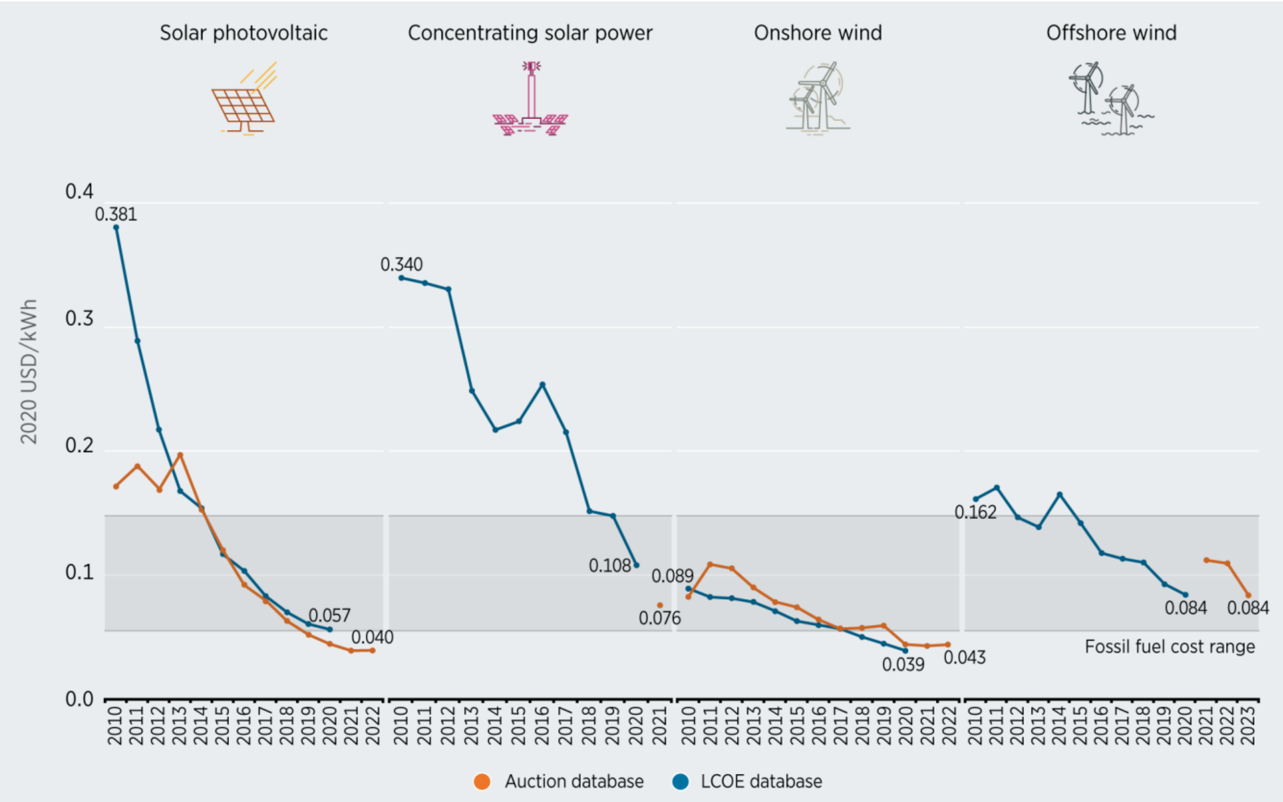

Figure 1: Evolution and of LCOE and PPA cost of renewable energy (ref. 5)

Due to the multi-stakeholder involvement in the data collection process, the technology catalogue contains data that has been scrutinised and discussed by a broad range of relevant stakeholders. This is essential because a main objective is to have the technology catalogue well-anchored amongst all stakeholders.

The technology catalogue will assist the long-term energy modelling in Ethiopia and support government institutions, private energy companies, think tanks and others with a common set of data of electricity producing technologies in Ethiopia in the future, broadly recognized by the energy sector. The data can be used for e.g., development of relevant policies and business strategies to achieve the government's long-term targets.

The Ethiopian Technology Catalogue builds on the approach of The Danish Technology Catalogue which has been developed by the Danish Energy Agency and Energinet for many years in an open process with stakeholders. The Ethiopian Technology Catalogue is inspired by a series of previously-conceived technology catalogues such as the Indonesian and the Vietnamese Technology Catalogues, published in 2017 and 2019 respectively. Furthermore, other relevant publications from the IEA and IRENA have been used as international references.

The text and data have been edited based on Ethiopian cases to represent local conditions. For the far future (2030 and 2050) international references have been relied upon for most technologies since Ethiopian data is expected to converge to these international values. In the short run differences may exist, especially for the emerging technologies. Differences in the short run can be caused by e.g., current rules and regulations (e.g. local content policies) and level of market maturity of the technology. Differences in both short and long run can also be caused by local physical conditions.

The current edition has been developed in close collaboration between MoWIE, EEP, the Danish Energy Agency and Ea Energy Analyses.

References

1. Energinet and Danish Energy Agency (2020): Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion. See also: ens.dk/en/our-services/projections-and-models/technology-data
2. IRENA (2018): Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi.
3. Sino-Danish Renewable Energy Development programme (2014): China Renewable Energy Technology Catalogue.
4. Department for Business, Energy & Industrial Strategy (2016): Electricity generation cost
5. IRENA (2021). Renewable power generation costs in 2020. www.irena.org

METHODOLOGY

The technologies described in this catalogue cover both very mature technologies and technologies which are expected to improve significantly over the coming decades, both with respect to performance and cost. This implies that the price and performance of some technologies may be estimated with a rather high level of certainty whereas in the case of other technologies both cost and performance today as well as in the future is associated with a high level of uncertainty. All technologies have been grouped within one of four categories of technological development (described in section about research and development) indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The boundary for both cost and performance data are the generation assets plus the infrastructure required to deliver the energy to the nearest grid. For electricity, this is the nearest substation of the transmission grid. This implies that a MW of electricity capacity of the plant represents the net electricity delivered, i.e., the gross generation minus the auxiliary electricity consumed at the plant. Hence, efficiencies are also net efficiencies.

Each technology is described by a separate technology sheet, following the format explained below.

Qualitative description

The qualitative description describes the key characteristic of the technology as concisely as possible. The following paragraphs are included if found relevant for the technology.

Technology description
Brief description for non-engineers of how the technology works and for which purpose.

Input
The main raw materials, primarily fuels, consumed by the technology.

Output
The output of the technologies in the catalogue is electricity. If relevant, other output such as process heat are mentioned here.

Typical capacities
The stated capacities are for a single unit (e.g., a single wind turbine or a single gas turbine), as well as for the total power plant consisting of a multitude of units such as a wind farm. The total power plant capacity should be that of a typical installation in Ethiopia.

Ramping configurations and other power system services
Brief description of ramping configurations for electricity generating technologies, i.e., what are the part load characteristics, how fast can they start-up, and how quickly are they able to respond to demand changes.

Advantages/disadvantages
Specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; for example, that renewable energy technologies mitigate climate risk and enhance security of supply.

Environment
Particular environmental characteristics are mentioned, e.g., special emissions or the main ecological footprints.

Employment
Description of the employment requirements of the technology in the manufacturing and installation process as well as during operation.

Research and development
The section lists the most important challenges from a research and development perspective. Particularly Ethiopian research and development perspectives is highlighted if relevant.

The potential for improving technologies is linked to the level of technological maturity. Therefore, this section also includes a description of the commercial and technological progress of the technology. The technologies are categorized within one of the following four levels of technological maturity. The correlation between accumulated production volume and price for the four categories is shown in Figure 2.

<u>Category 1</u>. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is very significant.

<u>Category 2</u>. Technologies in the *pioneer phase*. Through demonstration facilities or semi-commercial plants, it has been proven that the technology works. Due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. (e.g., gasification of biomass).

<u>Category 3</u>. *Commercial technologies with moderate deployment* so far. Price and performance of the technology today is well-known. These technologies are deemed to have a significant development potential and therefore there is a considerable level of uncertainty related to future price and performance (e.g., offshore wind turbines)

<u>Category 4</u>. *Commercial technologies, with large deployment* so far. Price and performance of the technology today is well-known, and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a fairly high level of certainty (e.g., coal power, gas turbine).

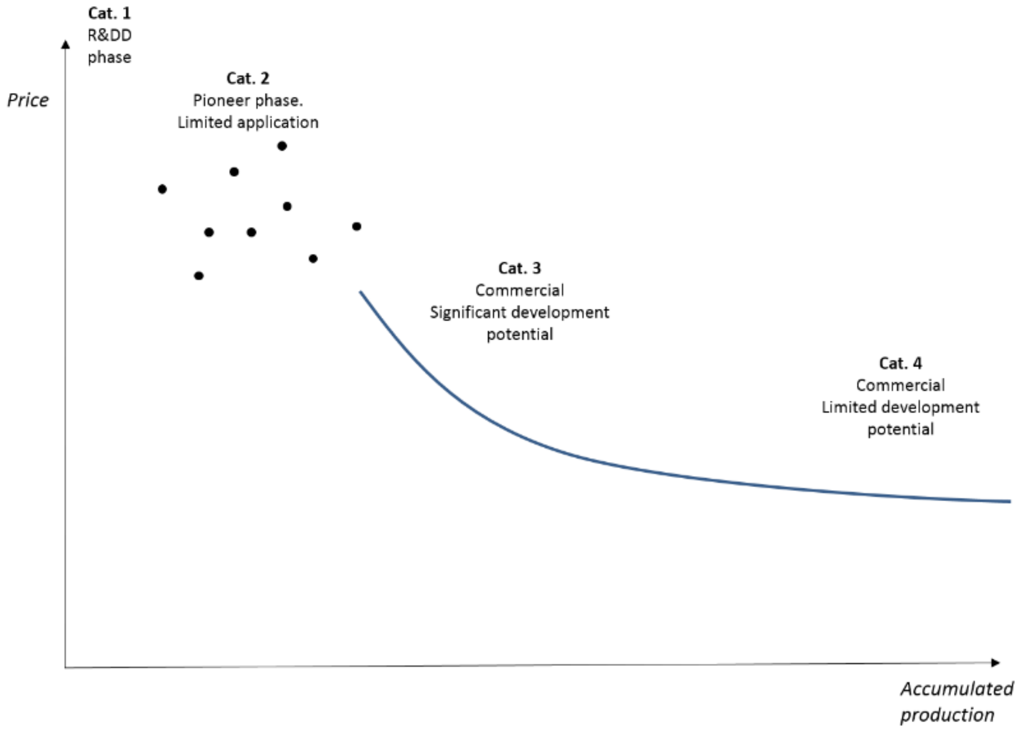

Figure 2: Technological development phases. Correlation between accumulated production volume (MW) and price.

Investment cost estimation

In this section *investment* cost projections from different sources are compared, when relevant. If available, local projects are included along with international projections from accredited sources (e.g., IRENA). On top of the table, the recommended cost figures are highlighted. Local investment cost figures are reported directly when available, otherwise they are derived from the result of PPAs, auctions and/or support mechanisms.

Cost projections based on the learning curve approach is added at the bottom of the table to show cost trends derived from the application of the learning curve approach (see the Appendix for a more detailed discussion). Technological learning is based on a certain learning rate and on the capacity deployment defined as the average of the IEA's Stated Policies and Sustainable Development. The single technology is given a normalized cost of 100% in 2020 (base year); values smaller than 100% for 2030 and 2050 represent the technological learning, thus the relative cost reduction against the base year. An example of the table is shown below.

Investment costs [MUSD$_{2019}$/MW]		**2018**	**2020**	**2030**	**2050**
Catalogues	**Technology catalogue for Ethiopia (2021)**				
Ethiopian data	Local data I				
	Local data II				
International data	Danish technology catalogue				
	IRENA				
	IEA WEO19				
Projection	Learning curve – cost trend [%]				

As for the uncertainty of investment cost data, the following approach was followed: for 2020 the lower and upper bound of uncertainty are derived from the cost span in the various sources analysed. For 2050, the central estimate is based on a learning rate of 12.5% and an average capacity deployment from the Stated Policies (STEP) and Sustainable Development (SD) scenarios of the World Energy Outlook 2019. The 2050 uncertainty range combines cost spans of 2020 with the uncertainty related to the technology deployment and learning: a learning rate range of 10-15% and the capacity deployment pathways proper of STEPS and SDS scenarios are considered to evaluate the additional uncertainty. The upper bound of investment cost, for example, will therefore be calculated as the upper bound for 2020 plus a cost development based on the scenario with a learning rate of 10% combined with the scenario with the lowest deployment towards 2050.

Examples of current projects
Recent technological innovations in full-scale commercial operation should be mentioned, preferably with references and links to further information. This is not necessarily a Best Available Technology (BAT), but rather a representative indication of the typical projects that are currently being commissioned.

Quantitative description

To enable comparative analyses between different technologies it is imperative that data is comparable. As an example, economic data is stated in the same price level and value added taxes (VAT) or other taxes are excluded. The reason for this is that the technology catalogue should reflect the socio-economic cost for the Ethiopian society. In this context taxes do not represent an actual cost but rather a transfer of capital between Ethiopian stakeholders, the project developer, and the government. Also, it is essential that data be given for the same years. Year 2020 is the base for the present status of the technologies, i.e., best available technology at the point of commissioning.

All costs are stated in U.S. dollars (USD), price year 2019. When converting costs from a year X to $2016 the following approach is recommended:

1. If the cost is stated in ETB, convert to USD using the exchange rate for year X (Table 1- first table).
2. Then convert from USD in year X to USD in 2019 using the relationship between the US Producer Price Index for "Engine, Turbine, and Power Transmission Equipment Manufacturing" of year X and 2019 (Table 1 - second table).

For example, a 1000 ETB in 2015 is converted to 0.048 USD (2015) using the exchange rate of 20.686. This further converted to 0.049 USD (2019) by multiplying to the ratio between PPI for 2019 and 2015 (i.e., 189/184.6 = 1.024).

Table 1: The yearly average exchange rate between ETB and $.

Year	ETB to $
2010	11.619
2011	16.974
2012	17.787
2013	18.154
2014	19.671
2015	20.686
2016	21.837
2017	23.967
2018	27.668
2019	29.212
2020	33.426

US Producer Price Index for "Turbine, and Power Transmission Equipment Manufacturing", Index Dec 1984 =100. This industry comprises establishments primarily engaged in manufacturing turbines, power transmission equipment, and internal combustion engines (except automotive gasoline and aircraft) (ref. 1).

Year	Producer Price Index
2007	152.6
2008	162.9
2009	174.6
2010	174.6
2011	177.7
2012	179.0
2013	180.9
2014	183.0
2015	184.6
2016	181.8
2017	181.8
2018	184.2
2019	189.0
2020	192.2
2021	196.4

The construction time, which is also specified in the data sheet, represents the time between the financial closure, i.e., when financing is secured, and all permits are at hand, and the point of commissioning.

The outline of a typical data sheet, containing all parameters used to describe the specific technologies, is discussed below. The data sheet consists of a generic part, which is identical for groups of similar technologies (thermal power plants, non-thermal power plants and heat generation technologies) and a technology specific part, containing information, which is only relevant for the specific technology. The generic technology part is made to allow for an easy comparison of technologies.

Each cell in the data sheet should only contain one number, which is the central estimate for the specific technology, i.e., no range indications. Uncertainties related to the figures should be stated in the columns called *uncertainty*. To keep the data sheet simple, the level of uncertainty is only specified for years 2020 and 2050. The level of uncertainty is illustrated by providing a lower and higher bound indicating a confidence interval of 90%. The uncertainty is related to the 'market standard' technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa). For certain technologies, the catalogue covers a product range, this is for example the case for coal power, where both subcritical, supercritical and ultra-supercritical power plants are represented.

The level of uncertainty needs only to be stated for the most critical figures such as for example investment costs and efficiencies.

Before using the data, please note that essential information may be found in the notes below the table.

Energy/technical data

The data tables hold information about 2020, 2030 and 2050. The year in the data table represents the first year of operation.

Generating capacity

The capacity is stated for both a single unit, e.g., a single wind turbine or gas engine, and for the total power plant, for example a wind farm or gas fired power plant consisting of multiple gas engines. The sizes of units and the total power plant should represent typical power plants. Factors for scaling data in the catalogue to other plant sizes than those stated are presented later in this methodology section.

The capacity is given as net generation capacity in continuous operation, i.e., gross capacity (output from generator) minus own consumption (house load), equal to capacity delivered to the grid.

The unit MW is used for electric generation capacity, whereas the unit MJ/s is used for fuel consumption.

This describes the relevant product range in capacity (MW), for example 200-1000 MW for a new coal-fired power plant. It should be stressed that data in the sheet is based on the typical capacity, for example 600 MW for a coal-fired power plant. When deviations from the typical capacity are made, economy of scale effects need to be considered (see the section about investment cost).

Energy efficiencies
Efficiencies for all thermal plants are expressed in percentage at lower calorific heat value (lower heating value or net heating value) at ambient conditions in Ethiopia, considering an average air temperature of approximately 28 °C.

The electric efficiency of thermal power plants equals the total delivery of electricity to the grid divided by the fuel consumption. Two efficiencies are stated: the nameplate efficiency as stated by the supplier and the expected typical annual efficiency.

Often, the electricity efficiency is decreasing slightly during the operating life of a thermal power plant. This degradation is not reflected in the stated data. As a rule of thumb, you may deduct 2.5 – 3.5% points during the lifetime (e.g., from 40% to 37%).

In case of technologies like hydro and wind, nameplate and annual efficiency is considered to be same.

Forced and planned outage
Forced outage is defined as number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the hours caused by unplanned outages, weighted according to how much capacity was out.

Forced outage is given in percent, while planned outage (for example due to renovations) is given in weeks per year.

Technical lifetime
The technical lifetime is the expected time for which an energy plant can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, power plant efficiencies often decrease slightly (few percent) over the years, and operation and maintenance costs increase due to wear and degradation of components and systems. At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low availability and/or high operations and maintenance costs. At this time, the plant would be decommissioned or undergo a lifetime extension, implying a major renovation of components and systems as required to make the plant suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience. In real life, specific plants of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g., the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime.

Construction time
Represents the time between the financial closure, i.e., when financing is secured, and all permits are at hand, until commissioning completed (start of commercial operation), expressed in years.

Space requirement
If relevant, space requirement is specified. The space requirements may among other things be used to calculate the rent of land, which is not included in the financial since the cost item depends on the specific location of the plant.

Average annual capacity factor
Unless otherwise stated, the thermal technologies in the catalogue are assumed to be designed for and operating for approx. 6000 full load hours of generation annually (capacity factor of just below 70%). Some of the exceptions are municipal solid waste generation facilities and geothermal power plants, which are designed for continuous operation, i.e., approximately 8000 full load hours annually (capacity factor of 90%).

For non-thermal power generation technologies, a typical average annual capacity factor is presented. The average annual capacity factor represents the average annual net generation divided by the theoretical annual net generation, if the plant were operating at full capacity all year round. The equivalent full load hours per year is determined by multiplying the capacity factor by 8,760 hours, the total number of hours in a year.

The capacity factors for technologies like solar, wind and hydropower are very site specific. In these cases, the typical capacity factor is supplemented with additional information, for example maps or tables, explaining how the capacity will vary depending on the geographic location of the power plant. This information is normally integrated in the brief technology description.

The theoretical capacity factor represents the production realised, assuming no planned or forced outages. The realised full-loads considers planned and forced outage.

Ramping configuration

The electricity ramping configuration of the technologies is described by four parameters:

- Ramping (% per minute) i.e., the ability to ramp up and down when the technology is already in operation.
- Minimum load (percent of full load): The minimum load from which the boiler can operate
- Warm start-up time, (hours): The warm start-up time, used for boiler technologies, is defined as the time for starting, from a starting point where the water temperature in the evaporator is above 100°C, which means that the boiler is pressurized.
- Cold, start-up time, (hours). The cold start-up time used for boiler technologies is defined as the time it takes to reach operating temperature and pressure and start production from a state where the boiler is at ambient temperature and pressure.

For several technologies, these parameters are not relevant, e.g., if the technology can ramp to full load instantly in on/off-mode.

Environment

The plants should be designed to comply with the regulation that is currently in place in Ethiopia and planned to be implemented within the 2020-time horizon.

CO_2 emission values are not stated, but these may be calculated by the reader of the catalogue by combining fuel data with technology efficiency data.

Emissions of particulate matter are expressed as $PM_{2.5}$ in gram per GJ fuel.

SO_x emissions are calculated based on the following sulphur contents of fuels:

	Coal	Fuel oil	Gas oil	Natural gas	Wood	Waste	Biogas
Sulphur (kg/GJ)	0.35	0.25	0.07	0.00	0.00	0.27	0.00

The Sulphur content can vary for different kinds of coal products. The Sulphur content of coal is calculated from a maximum sulphur weight content of 0.8%.

For technologies where desulphurization equipment is employed (typically large power plants), the degree of desulphurization is stated in percentage terms.

NO_x emissions represent emissions of NO_2 and NO, where NO is converted to NO_2 in weight-equivalents. NO_x emissions are also stated in grams per GJ fuel.

Emissions of methane (CH_4) and Nitrous oxide (N_2O) are not included in the catalogue. However, these are both potent greenhouse gas, and for certain technologies, for example for gas turbines, the emissions can be relevant to include. In further development of the catalogue these emissions could also be included.

Financial data

Financial data are all in $ fixed prices, price level 2019 and exclude value added taxes (VAT) or other taxes.

For projection of future financial costs there are three overall approaches: Engineering bottom-up, Delphi-survey, and Learning curves. This catalogue uses the learning curve approach. The reason is that this method has proved historically robust and that it is possible to estimate learning rates for most technologies. See Appendix.

Investment costs

The investment cost or initial cost is often reported on a normalized basis, e.g., cost per MW. The nominal cost is the total investment cost divided by the net generating capacity, i.e., the capacity as seen from the grid.

If possible, the investment cost is divided into equipment cost and installation cost. Equipment cost covers the plant itself, including environmental facilities, whereas installation costs cover buildings, grid connection and installation of equipment.

Different organizations employ different systems of accounts to specify the elements of an investment cost estimate. Since there is no universally employed nomenclature, investment costs do not always include the same items. Actually, most reference documents do not state the exact cost elements, thus introducing an unavoidable uncertainty that affects the validity of cost comparisons. Also, many studies fail to report the year (price level) of a cost estimate.

In this report, the intention is that investment cost shall include all physical equipment, typically called the engineering, procurement and construction (EPC) price or the *overnight cost*. Connection costs are included, but reinforcements are not included. It is here an assumption that the connection to the grid is within a reasonable distance.

The rent or buying of land is *not* included but may be assessed based on the space requirements specified under the energy/technical data. The reason for the land not being directly included, is that land, for the most part, do not lose its value. It can therefore be sold again after the power plant has fulfilled its purpose and been decommissioned.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, and approvals by authorities) and interest during construction are not included. The cost to dismantle decommissioned plants is also not included. Decommissioning costs may be offset by the residual value of the assets.

Cost of grid expansion
As mentioned before, grid connection costs are included, however possible costs of grid expansion from adding a new electricity generator to the grid are not included in the presented data.

Business cycles
Business cycles follow general and cross-sectoral economic trends. As an example, the cost of energy equipment surged in 2007-2008 in conjunction with the financial crisis outbreak. In a study assessing generation costs in the UK in 2010, Mott MacDonald reported that "After a decade of cycling between $400 and $600 a kW installed EPC prices for CCGT increased sharply in 2007 and 2008 to peak at around $1250/kW in Q3:2008. This peak reflected tender prices: no actual transactions were done at these prices."

Such unprecedented variations obviously make it difficult to benchmark data from the recent years; furthermore, predicting the outbreak of global recessions and their impact on complex supply chains (such as the Covid-19 2020 crisis) is challenging. However, a catalogue as the present needs to refer to several sources and assume future courses. The reader is urged to bear this in mind when comparing the costs of different technologies.

Economy of scale
The per unit cost of larger power plants is usually lower than that of smaller plants. This is the effect of 'economy of scale'. An empirical relationship between power plant size and their cost was analysed in the article "Economy of Scale in Power Plants" in the August 1977 issue of Power Engineering Magazine (p. 51). The basic equation linking costs and sizes of two different power plants is:

$$\frac{C_1}{C_2} = \left(\frac{P_1}{P_2}\right)^a$$

Where: C_1 = Investment cost of plant 1 (e.g., in million US$)
C_2 = Investment cost of plant 2
P_1 = Power generation capacity of plant 1 (e.g., in MW)

P_2 = Power generation capacity of plant 2
α = Proportionality factor

For many years, the proportionality factor averaged about 0.6, but extended project schedules may cause the factor to increase. However, used with caution, this rule may be applied to convert data in this catalogue to other plant sizes than those stated. It is important that the plants are essentially identical in construction technique, design, and time frame and that the only significant difference is size.

For very large-scale plants, like large coal power plants, we may have reached a practical limit, since very few investors are willing to add increments of 1000 MW or above. Instead, by building multiple units at the same spot can provide sufficient savings through allowing sharing of balance of plant equipment and support infrastructure. Typically, about 15% savings in investment cost per MW can be achieved for gas combined cycle and big steam power plant from a twin unit arrangement versus a single unit ("Projected Costs of Generating Electricity", IEA, 2010). The financial data in this catalogue are all for single unit plants (except for wind farms and solar PV), so one may deduct 15% from the investment costs, if very large plants are being considered.

Unless otherwise stated the reader of the catalogue may apply a proportionality factor of 0.6 to determine the investment cost of plants of higher or lower capacity than the typical capacity specified for the technology. For each technology, the relevant product range (capacity) is specified.

Operation and maintenance (O&M) costs
The fixed share of O&M is calculated as cost per generating capacity per year ($/MW/year), where the generating capacity is the one defined at the beginning of this chapter and stated in the tables. It includes all costs, which are independent of how many hours the plant is operated, e.g., administration, operational staff, payments for O&M service agreements, network or system charges and insurance. Any necessary reinvestments to keep the plant operating within the technical lifetime are also included, whereas reinvestments to extend the life beyond the technical lifetime are excluded. Reinvestments are discounted at annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if data is available.

The variable O&M costs ($/MWh) include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances). Planned and unplanned maintenance costs may fall under fixed costs (e.g., scheduled yearly maintenance works) or variable costs (e.g., works depending on actual operating time) and are split accordingly.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

References
1. U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Turbine and Power Transmission Equipment Manufacturing [PCU33363336], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/PCU33363336.

1. HYDROPOWER PLANTS

Brief technology description

Hydropower has been a reliable and proven method for electricity production for over a century. The concept exploits the *head* difference between two water reservoirs, be it natural or artificially created through dams and weirs. In a hydropower plant, the potential energy is converted into rotational kinetic energy, which spins the blades of a turbine connected to a generator.

Hydropower plants can be classified in different ways, which for instance distinguish among head availability, plant size and operational regime. In terms of operational regime, the following classification is widely accepted (ref. 1):

- **Run-of-river (RoR) plants**. A facility that channels flowing water from a river through a canal or penstock to spin a turbine. Typically, a run-of-river project has little or no storage facility. They are typically small and find application also in off-grid contexts.
- **Storage/reservoir plants**. Uses a dam to store water in a reservoir (water impoundment). Electricity is produced by discharging water from the reservoir through a turbine, which activates a generator. They can span over a wide range of capacities, depending on the hydraulic head and reservoir size.
- **Pumped storage plants**. Provides peak load supply, harnesses water which is cycled between a lower and upper reservoir by pumps which use surplus energy from the system at times of low demand. While plenty of pumped hydro storage plants exist and are under construction in the world, Ethiopia does not have any of these facilities.

A scheme for RoR and reservoir plants is presented in Figure 3.

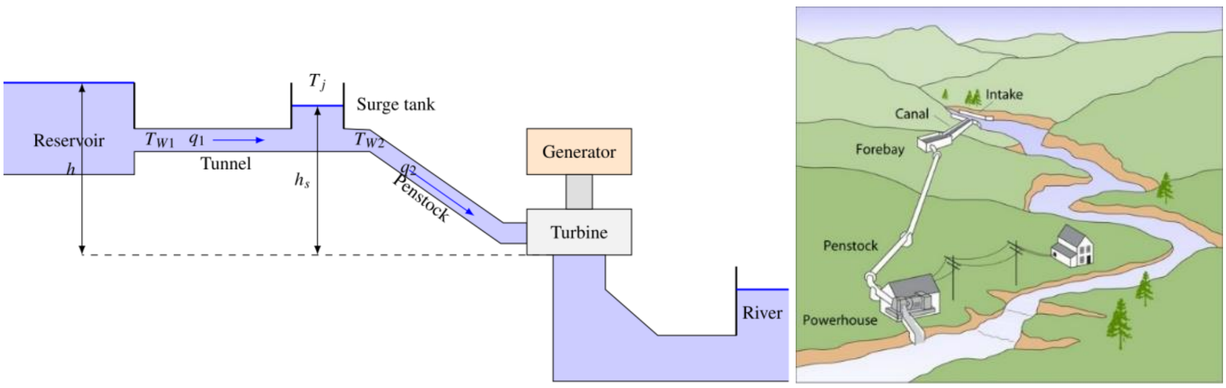

Figure 3: Reservoir and run-of-river hydropower plants (ref. 2, 3).

Run-of-river and reservoir hydropower plants can be combined in cascading river systems and pumped storage plants can utilize the water stored in one or several reservoir hydropower plants. In cascading systems (Figure 4), the energy output of a run-of-river hydropower plant can be regulated by an upstream reservoir hydropower plant. A large reservoir in the upper catchment generally regulates outflows for several run-of-rivers or smaller reservoir plants downstream. This likely increases the yearly energy potential of downstream sites and enhances the value of the upper reservoir's storage function. However, this also creates the dependence of downstream plants to the commitment of the upstream plants.

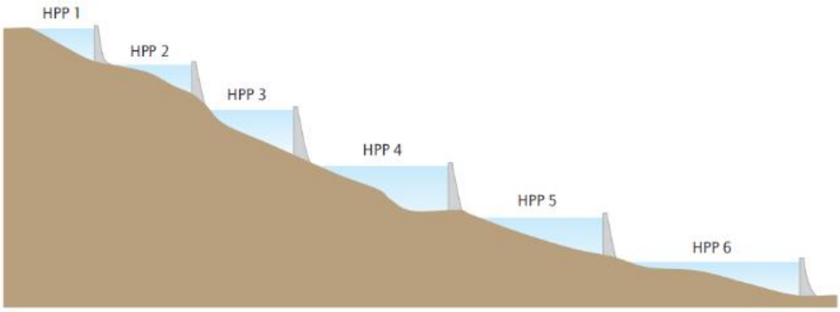

Figure 4: Cascading Systems (ref. 4)

Hydropower systems can range from tens of Watts to hundreds of Megawatts. A classification based on the size of hydropower plants is presented in Table 2.

Table 2: Classification of hydropower plants based on size (ref. 1).

Type	**Capacity (international classification)**	**Capacity (Ethiopian classification)**
Large hydropower	> 100 MW	>30 MW
Medium hydropower	25 – 100 MW	10 – 30 MW
Small hydropower	1- 25 MW	1 – 10 MW
Mini/micro/pico hydropower	< 1000 kW	< 1000 kW

Large hydropower plants often have outputs of hundreds or even thousands of megawatts and use the energy of falling water from the reservoir to produce electricity using a variety of available turbine types (e.g., Pelton, Francis, Kaplan) depending on the characteristics of the river, the hydraulic head and installation capacity. Small, micro and pico hydropower plants are run-of-river schemes. These types of hydropower use Cross-flow, Pelton, or Kaplan turbines. The selection of the turbine type depends on the head and flow rate of the river, as visible in Figure 5. In Ethiopia, Francis turbines are the most common type of energy conversion machine adopted, while Kaplan turbines have found no current application.

For high heads and small flows, Pelton turbines are used, in which water passes through nozzles and strikes spoon-shaped buckets arranged on the periphery of a wheel. A less efficient variant is the cross-flow turbine. These are action turbines, working only from the kinetic energy of the flow.

For low heads and large flows, Kaplan turbines, a propeller-type water turbine with adjustable blades, dominate. Kaplan and Francis turbines, like other propeller-type turbines, capture the kinetic energy and the pressure difference of the fluid between entrance and exit of the turbine. Francis turbines are the most common type, as they accommodate a wide range of heads (20 m to 700 m), small to very large flows, a broad rate capacity and excellent hydraulic efficiency.

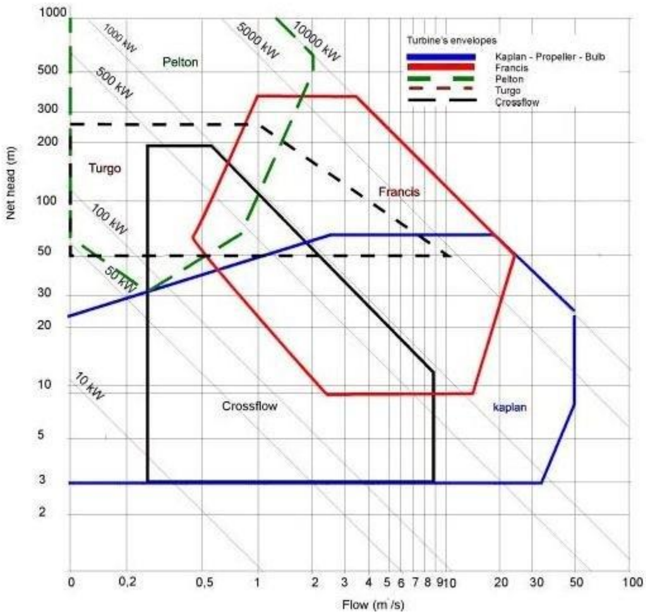

Figure 5: Hydropower turbine application chart *(ref. 5)*

The capacity factor achieved by hydropower projects needs to be looked at somewhat differently than for other renewable projects. It depends on the availability of water and the purpose of the plants whether for meeting peak and/or base demand. The average capacity factor of hydropower plants settled at 48% in 2010-2019 (world figures), with a significant standard deviation across geography (Figure 6).

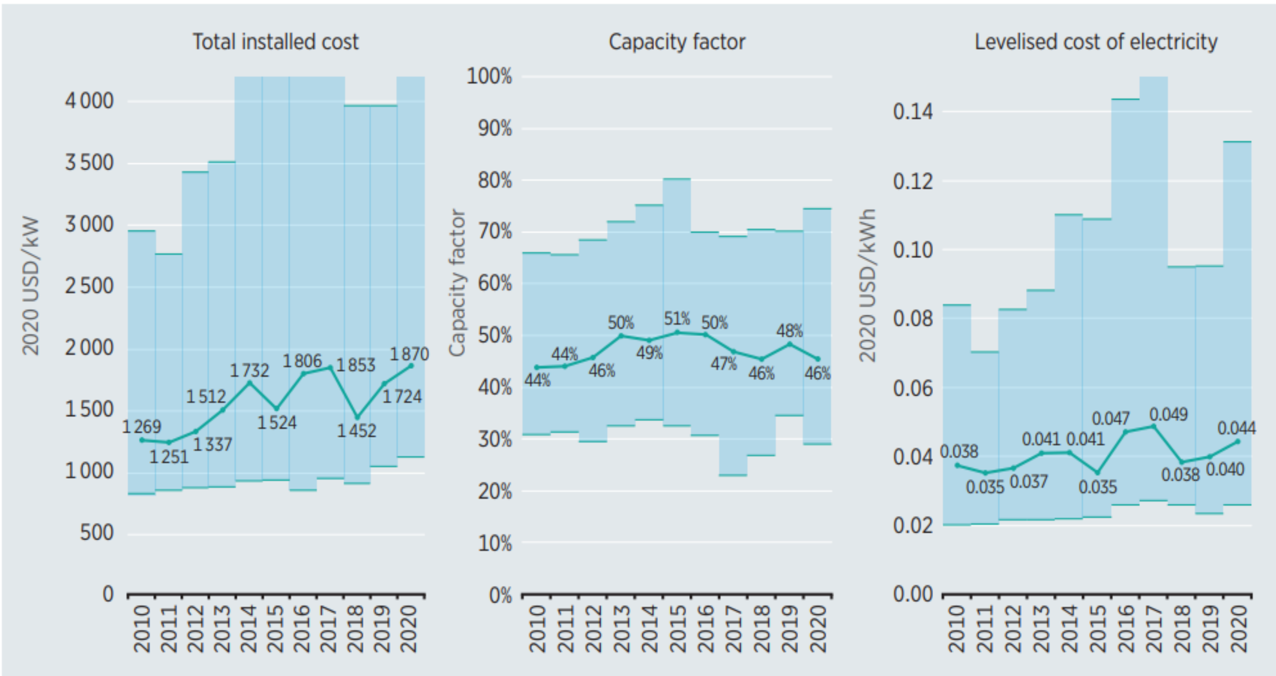

Figure 6: Total installed cost, capacity factor, LCOE for hydropower in the world. Blue areas represent the standard deviation from the average (ref. 6).

Input

The water from either reservoir or run-of-river having certain head [m] and flow rate [m³/s].

Output
Electricity.

Typical capacities
Hydropower systems can range from tens of Watts to hundreds of Megawatts. Currently up to 900 MW per unit (ref. 7). According to the local case data received, the expected plant capacity for future plants in Ethiopia is expected to have a wide range (5 to over 1000 MW).

Ramping configurations
Hydropower helps to maintain the power frequency by continuous modulation of active power, and to meet moment-to-moment fluctuations in power requirements. It offers rapid ramp rates and a broad operational regime, making it very efficient to follow steep load variations or the intermittent power supply of renewable energy such as wind and solar power plants.

Advantages/disadvantages
Advantages:
- Hydropower is a clean source, as it doesn't pollute the air.
- Hydropower is a domestic source of energy.
- Hydropower is a renewable power source.
- Hydropower with storage is generally available as needed; operators can control the flow of water through the turbines to produce electricity, which provides flexibility to the system.
- Hydroelectric energy offers grid support in case of major electricity outages, given their ability to ramp up in a short time.
- Hydropower facilities have a long service life, which can be extended indefinitely, and further improved. Some operating facilities in certain countries are 100 years and older. This makes for long-lasting, affordable electricity.
- Other benefits may include water supply, irrigation, and flood control.
- Hydropower is quite safe as there is no combustion of fuel involved.
- Hydropower plants do not require a lot of staff, and maintenance costs are usually low.
- Impoundments offer a variety of recreational activities such as fishing and boating.

Disadvantages:
- Fish populations can be impacted if fish cannot migrate upstream past impoundment dams to spawning grounds or if they cannot migrate downstream to the ocean.
- Hydropower can impact water quality and flow. Hydropower plants can cause low dissolved oxygen levels in the water, a problem that is harmful to riverbank habitats.
- Hydropower plants can be impacted by drought. When water is not available, the hydropower plants can't produce electricity.
- Hydropower plants can be impacted by sedimentation. Sedimentation affects the safety of dams and reduces energy production, storage, discharge capacity and flood attenuation capabilities. It increases loads on the dam and gates and damages mechanical equipment.
- New hydropower facilities impact the local environment and may compete with other uses for the land. Those alternative uses may be more highly valued than electricity generation. Humans, flora, and fauna may lose their natural habitat. Local cultures and historical sites may be impinged upon.
- Even though hydropower is a flexible renewable energy source there are often limits to the flexibility caused by irrigation needs and other needs.
- Hydropower plants have a high initial cost, requiring investors that can finance the plant.
- There is a limited amount of areas that are suitable for dam construction and/or where hydraulic head is big enough to justify a project. Often hydropower plants are located far from big aggregate loads (cities), which might require additional expenditures for grid development/strengthening.

- Dams can cause the settlements to move should these be in proximity of the flooded area.
- In many hydro plants across the globe, eutrophication leads to potential methane emissions.

Environment
Environmental issues identified in the development of hydropower include:

- Safety issues: Hydropower is very safe today. Losses of life caused by dam failure have been very rare in the last 30 years. The population at risk has been significantly reduced through the routing and mitigation of extreme flood events.
- Water use and water quality impacts. The impact of hydropower plants on water quality is very site specific and depends on the type of plant, how it is operated and the water quality before it reaches the plant. Dissolved oxygen (DO) levels are an important aspect of reservoir water quality. Large, deep reservoirs may have reduced DO levels in bottom waters, where watersheds yield moderate to heavy amounts of organic sediments.
- Impacts on migratory species and biodiversity; Older dams with hydropower facilities were often developed without due consideration for migrating fish. Many of these older plants have been refurbished to allow both upstream and downstream migration capability.
- Implementing hydropower projects in areas with low or no anthropogenic activity. In areas with low or no anthropogenic activity the primary goal is to minimize the impacts on the environment. One approach is to keep the impact restricted to the plant site, with minimum interference over forest domains at dams and reservoir areas, e.g., by avoiding the development of villages or cities after the construction periods.
- Reservoir sedimentation and debris. This may change the overall geomorphology of the river and affect the reservoir, the dam/power plant, and the downstream environment. Reservoir storage capacity can be reduced, depending on the volume of sediment carried by the river.
- Life-cycle greenhouse gas emissions. Life-cycle CO_2 emissions from hydropower originate from construction, operation and maintenance, and dismantling. Possible emissions from land use related net changes in carbon stocks and land management impacts are very small.

Employment
Generally, a large new hydropower plant (110 MW) project will provide around 2,000 – 3,000 local jobs during the construction phase. The kind of jobs expected are technicians, welders, joineries, carpenters, porters, project accountants, electrical and mechanical engineers, cooks, cleaners, masons, security guards and many others. Of those, about 150 - 200 will continue to work at the facility for operations and maintenance (ref. 8).

Research and development
Hydropower is a very mature and well-known technology (category 4). While hydropower is the most efficient power generation technology, with high energy payback ratio and conversion efficiency, there are still many areas where small but important improvements in technological development are needed.

Turbine design

- The hydraulic efficiency of hydropower turbines has shown a gradual increase over the years: modern equipment reaches 90% to 95% (Figure 7). This is the case for both new turbines and the replacement of existing turbines (subject to physical limitations).

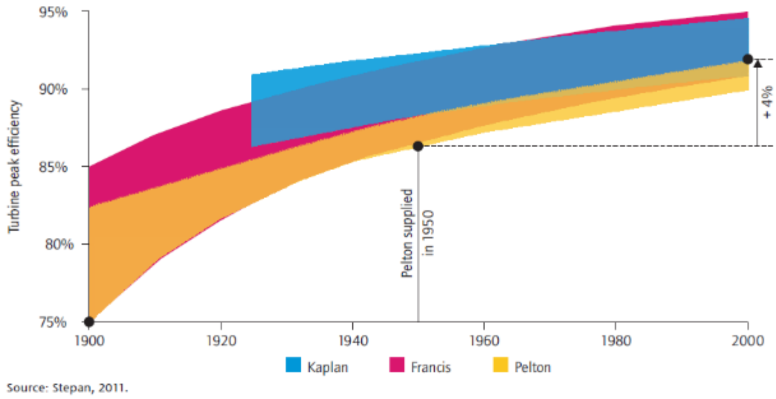

Figure 7: Improvement of hydraulic performance over time (ref. 9)

Some improvements aim directly at reducing the environmental impacts of hydropower by developing

- Fish-friendly turbines
- Aerating turbines
- Oil-free turbines

- Hydrokinetic turbines; Kinetic flow turbines for use in canals, pipes, and rivers. In-stream flow turbines, sometimes referred to as hydrokinetic turbines, rely primarily on the conversion of energy from free-flowing water, rather than from hydraulic head created by dams or control structures. Most of these underwater devices have horizontal axis turbines, with fixed or variable pitch blades.
- Bulb (Tubular) turbines; Nowadays, very low heads can be used for power generation in a way that is economically feasible. Bulb turbines are efficient solutions for low head, up to 30 m. The term "Bulb" describes the shape of the upstream watertight casing which contains a generator located on a horizontal axis. The generator is driven by a variable pitch propeller (or Kaplan turbine) located on the downstream end of the bulb.
- Improvements in civil works; The cost of civil works associated with new hydropower project construction can be up to 70% of the total project cost, so improved methods, technologies and materials for planning, design and construction have considerable potential (ref. 2). A roller-compacted concrete (RCC) dam is built using much drier concrete than traditional concrete gravity dams, allowing speedier and lower cost construction.
- Upgrade or redevelop old plants to increase efficiency and environmental performance.
- Add hydropower plant units to existing dams or water flows.

Investment cost estimation

The investment cost here is estimated considering local estimated cost for planned plants, international data and learning curve approach (discussed in appendix) based on the IEA WEO19. The distinction between large and medium over here is considered based on international classification.

Investment costs [MUSD$_{2019}$/MW]		2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**2.4** (large) **3.7** (medium)	**2.3** (large) **3.55** (medium)	**2.14** (large) **3.29** (medium)
Ethiopian data	Local cases	2.4 (large) 3.7 (medium)			
International data	IRENA (2012) Africa	2.16 (large) 3.24 (medium)			
Projection	Learning curve – cost trend [%]		100%	96%	89%

The investment cost of hydropower in Ethiopia is based on feasibility studies which might benefit a revision to represent more up to date values.
The cost of hydropower is strongly dependent on the topology of the mountains where it is constructed and the hydro resources. Therefore, it is difficult to estimate a standard value for investment costs that can be used for new hydropower plants. However, it is highly recommended to take local conditions into account when estimating investment costs for hydro plants in energy planning. Furthermore, as hydropower is a mature technology the expected cost reduction is relatively conservative. In addition to that it is difficult to separate out how some specific improvements might impact the overall cost especially after considering the fact that most of the best locations for hydro are probably already exploited.

Examples of current projects
Ethiopia is endowed with a significant hydropower potential. Eight major river basins are present in the country, with a potential of over 48 GW (Ministry of Water, Irrigation and Energy, 2019). Some plant types are currently not installed in Ethiopia, e.g., pumped hydro storage and below-1MW hydro facilities (mini, micro and pico hydropower).

Hydropower is responsible for most of the electricity production in Ethiopia. Hydro plants have been a part of the system for a very long time with Abs Samuel commissioned in 1931 and still under operation. The other plants currently operational in the system are Awash II and III, Beles, Fincha, Finchaa Amerti Neshe, Genale Dawa III, Gibe I, II and III, Koka, Maleka Wakana, Tekeze I, Tis Abay I and II with a total installed capacity of around 4068 MW – Figure 8 shows the location of the hydropower plants on the Ethiopian map. These plants are installed in locations with flow rates ranging from 18 to over 1000 m^3/s and rated head ranging from 46 m to over 500 m, highlighting the wide range of resource locations available in Ethiopia. Furthermore, for plants like Fincha, Finchaa Amerti Neshe and Gibe II the rated head is ~500m warranting the use of Pelton turbines. The other plants have Francis turbines.

Currently in Ethiopia there are two mega hydroelectric projects under construction. Koysha Hydroelectric Project is one of these two projects under construction. It consists of a roller compacted concrete (RCC) dam, necessary to impound approximately 6 billion cubic meters of water. The plant will generate electricity by using eight Francis turbine units, 270 MW each, making the total installed capacity 2,160 MW and total rated discharge of 1,536 m^3/s. The project is expected to have a total cost of 2.8 billion USD and will be commissioned by 2023.

The Grand Ethiopian Renaissance Dam (GERD) is the other Hydro power project under construction consisting of a roller compacted concrete (RCC) dam and a rockfill saddle dam, necessary to impound approximately 63 billion cubic meters of water. It will have an installed capacity of 5,150 MW at a total cost of 3.7 billion USD and will be commissioned in three phases by 2024.

Additionally, there are plans to have a total installed capacity of 9300 MW from candidate hydro power plants like Beko Abo, Geba 1 and 2, Genale 6, Genale 5, Dabus, Birbir Werabesa + Halele, Tams, Baro 1 and 2, Genji, Wabi Shebele, Karadobi, Upper Mendaya, Chimoga yada and Diedesa. These will potentially be commissioned between 2026-2030. GERD and Koysha are special cases due to the size of the projects. The cost for the other candidate projects listed above is comparatively higher with an average estimated investment cost of 2.4 MUSD/MW.

Figure 8: GIS map with basin areas in Ethiopia and the locations of hydropower plants

Norwegian example

Many current hydro projects around the world are not new plants but upgrades of existing plants. These projects can involve including new catchment areas (increasing the yearly generation) or increasing the size of the reservoirs and adding turbine capacity. Higher capacity (for the same inflow) can make the plant more suitable for peak load which might be needed to balance wind and solar power. One such modernisation and extension project is the Nedre Rossaga station in Norway, which was completed in 2016. In addition to modernising the existing turbines, a new power station with an additional turbine unit was installed, increasing total installed capacity from 250 MW to 350 MW.

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9. IHA, 2017. "2017 IHA Hydropower Report", International Hydropower Association, London,

Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Technology

Technology	Hydro power plant - 100 to 2000 MW								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	150	150	150	100	2000	100	2000		1,8,10
Generating capacity for total power plant (MWe)	150	150	150	100	2000	100	2000		1,8,10
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	A	7
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	A	7
Forced outage (%)	4	4	4	2	10	2	10		1
Planned outage (weeks per year)	6	6	6	3	10	3	10		1
Technical lifetime (years)	50	50	50	40	90	40	90	B	1
Construction time (years)	4	4	4	2	6	2	6		1
Space requirement (1000 m^2/MWe)	62	62	62	47	78	47	78	C	1
Additional data for non thermal plants									
Capacity factor (%), theoretical	50	50	50	20	95	20	95		1
Capacity factor (%), incl. outages	46	46	46	20	95	20	95		1,2
Ramping configurations									
Ramping (% per minute)	50	50	50	30	100	30	100		3
Minimum load (% of full load)	0	0	0	0	0	0	0		3
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.40	2.30	2.14	1.80	3.50	1.60	2.67	D,E,F	1,4,5,6,9
- of which equipment	30%	30%	30%	20%	50%	20%	50%		11
- of which installation	70%	70%	70%	50%	80%	50%	80%		11
Fixed O&M ($/MWe/year)	18,000	18,000	18,000	13,500	22,500	13,500	22,500	C	1,4,5,6
Variable O&M ($/MWh)	0.65	0.65	0.65	0.49	0.81	0.49	0.81	C	1,5
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:

1 Data on local cases from EEP

2 Branche, 2011, “Hydropower: the strongest performer in the CDM process, reflecting high quality of hydro in comparison to other renewable energy sources”.

3 Eurelectric, 2015, "Hydropower - Supporting a power system in transition".

4 IEA, World Energy Outlook, 2015.

5 Learning curve approach for the development of financial parameters.

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7 Stepan, 2011, Workshop on Rehabilitation of Hydropower, “The 3-Phase Approach”.

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9 Energy and Environmental Economics, 2014, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC’s 10- and 20-Year Studies".

10 General Electric, www.gerenewableenergy.com, Accessed: 20th July 2017

11 ASEAN, 2016, "Levelised cost of electricity of selected renewable technologies in the ASEAN member states".

Notes:

A This is the efficiency of the utilization of the waters potential energy. This can not be compared with a thermal power plant that has to pay for its fuel.

B Hydro power plants can have a very long lifetime if operated and mainted properly. Hover Dam in USA is almost 100 years old.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.

E Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

Technology

Technology	Hydro power plant - 10 to 100 MW								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	50	50	50	10	100	10	100		2
Generating capacity for total power plant (MWe)	50	50	50	20	100	20	100		2
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	A	1
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	A	1
Forced outage (%)	4	4	4	2	10	2	10		1
Planned outage (weeks per year)	6	6	6	3	10	3	10		1
Technical lifetime (years)	50	50	50	40	90	40	90		1
Construction time (years)	3	3	3	2	6	2	6		1
Space requirement (1000 m^2/MWe)	14	14	14	11	18	11	18	B	
Additional data for non thermal plants									
Capacity factor (%), theoretical	88	88	88	50	95	50	95		2
Capacity factor (%), incl. outages	84	84	84	50	95	50	95		2,8
Ramping configurations									
Ramping (% per minute)	50	50	50	30	100	30	100		3
Minimum load (% of full load)	0	0	0	0	0	0	0		3
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	3.70	3.55	3.29	3.00	4.00	2.47	4.12	C,D	2,4,5,6,7
- of which equipment	30%	30%	30%	20%	50%	20%	50%		7
- of which installation	70%	70%	70%	50%	80%	50%	80%		7
Fixed O&M ($/MWe/year)	18,000	18,000	18,000	13,500	22,500	13,500	22,500		2,4,5,7
Variable O&M ($/MWh)	0.50	0.50	0.50	0.38	0.63	0.38	0.63	B	1
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:

1 Stepan, 2011, Workshop on Rehabilitation of Hydropower, “The 3-Phase Approach”.
2 Data on local cases from EEP
3 Eurelectric, 2015, "Hydropower - Supporting a power system in transition".
4 Energy and Environmental Economics, 2014, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC’s 10- and 20-Year Studies".
5 IEA, World Energy Outlook, 2015.
6 IEA, Projected Costs of Generating Electricity, 2015.
7 ASEAN, 2016, "Levelised cost of electricity of selected renewable technologies in the ASEAN member states".
8 Branche, 2011, “Hydropower: the strongest performer in the CDM process, reflecting high quality of hydro in comparison to other renewable energy sources”.

Notes:

A This is the efficiency of the utilization of the waters potential energy. This can not be compared with a thermal power plant that have to pay for its fuel.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.
D Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

2. WIND TURBINES

Brief technology description

The typical large onshore wind turbine being installed today is a horizontal axis, three bladed, upwind, grid connected turbine using active pitch, variable speed, and yaw control to optimize generation at varying wind speeds.

Wind turbines work by capturing the kinetic energy in the wind with the rotor blades and transferring it to the drive shaft. The drive shaft is connected either to a speed-increasing gearbox coupled with a medium- or high-speed generator, or to a low-speed, direct-drive generator. The generator converts the rotational energy of the shaft into electrical energy. In modern wind turbines, the pitch of the rotor blades is controlled to maximize power production at low wind speeds, and to maintain a constant power output and limit the mechanical stress and loads on the turbine at high wind speeds. A general description of the turbine technology and electrical system, using a geared turbine as an example, can be seen in Figure 9.

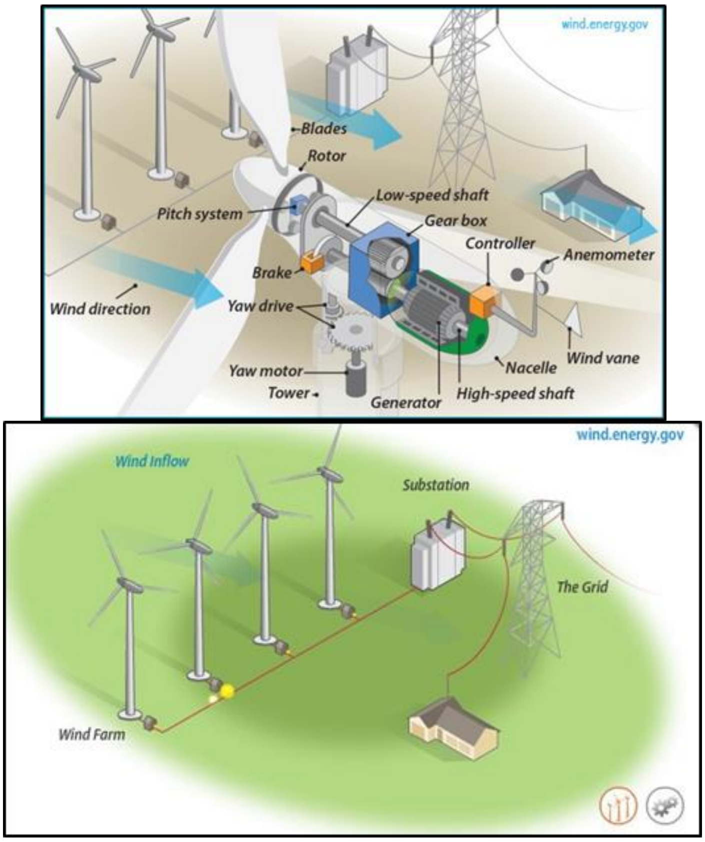


Figure 9: General turbine technology and electrical system

Wind turbines are designed to operate within a wind speed range, which is bounded by a low "cut-in" wind speed and a high "cut-out" wind speed. When the wind speed is below the cut-in speed the energy in the wind is too low to be utilized. When the wind reaches the cut-in speed, the turbine begins to generate. As the wind speed increases, the power output of the turbine increases, and at a certain wind speed the turbine reaches its rated power. At higher wind speeds, the blade pitch is controlled to maintain the rated power output. When the wind speed reaches the cut-out speed, the turbine is shut down or operated in a reduced power mode to prevent mechanical damage.

Three major parameters define the design of a wind turbine. These are hub height, nameplate capacity (or rated power) and rotor diameter. The last two are often combined in a derived metric called "specific power", which is the ratio between nameplate capacity and swept area. The specific power is measured in W/m^2.

The wind turbine design depends on the wind conditions at the site. In the IEC61400-1:2005, the International Electrotechnical Commission (IEC) defines three types of wind classes, as reported in Table 3. Values in this table should not be considered as point value, but rather representative of a range of possible wind speeds. These classes can be further divided into turbulence class A, B, and C. This is based on turbulence intensity, which quantifies how much the wind varies typically within 10 minutes.

Table 3: Wind site classification according to the IEC.

	Class I (High wind, HW)	**Class II (Medium wind, MW)**	**Class III (Low wind, LW)**
Average annual wind speed at hub height [m/s]	10	8.5	7.5
50-year extreme wind speed over 10 minutes [m/s]	50	42.5	37.5
50-year extreme wind speed over 3 seconds [m/s]	70	59.5	52.5

The turbine design differs consistently depending on the type of wind resource. At low wind (LW) sites, turbines are generally taller and sweep a larger area. In other terms, they are characterized by taller hubs and a smaller specific power. This way, turbines access higher wind speeds (the wind speed increases with height above ground) and manage to convert more wind power into electricity. In fact, the wind power picked up by the turbine is proportional to the swept area A and the third power of the wind speed v:

$$P = 0.5 \cdot \rho \cdot A \cdot v^3$$

ρ being the air density. The real electric power delivered to the grid is affected by mechanical and electrical conversion efficiencies. With a different turbine design, LW turbines can reach an annual production comparable to that of HW turbines which, on the contrary, are physically smaller. Advancements in the design of Class III wind turbines allow less windy sites to also be considered for the development of wind projects.

Onshore wind turbines can be installed as single turbines, clusters or in larger wind farms. Commercial wind turbines are operated unattended and are monitored and controlled by a supervisory control and data acquisition (SCADA) system.

The arrangement of the technical requirements within grid codes varies between electricity systems. See ref. 16 and 17. However, for simplicity the typical requirements for generators can be grouped as follows:

- Tolerance - the range of conditions on the electricity system for which wind farms must continue to operate
- Control of reactive power - often this is related to voltage control requirements in the network
- Control of active power
- Protective devices
- Power quality.

According to Solar and Wind Energy Resource Assessment (SWERA) conducted by Hydrochina in July 2012, Ethiopia has roughly 1000GW of wind potential. However, only a part of this resource could be exploited for on-grid applications.

Unlike the Solar PV farms, the Wind farms require intensive data collection and E & S impact assessment works. Keeping this in mind, Ethiopia's Ministry of Water, Irrigation and Electricity of Ethiopia (MOWIE), World Bank and Danish Government have set up partnership to launch Accelerating Wind Power Generation in Ethiopia program. The main targets for this program are to ensure availability of high quality wind resource assessments at a number of prioritized sites, assist collection of high quality wind resource data national using the 17 installed masts. These activities are aimed at enabling the participation of private developers in addition to the government for the preparation of bankable wind energy IPP auctions. As a part of this activity the World Bank Group (WBG) and the Danish Government have been providing technical support by assisting in the analysis and verification of wind measurements by screening potential wind farm sites suitable for auction processes. Nine sites have been identified for further investigation.

Input
The input is wind. Cut-in wind speed is 3-4 m/s. Rated power generation wind speed is 10-12 m/s. Cut-out or transition to reduced power operation occurs at wind speed around 22-25 m/s.

The annual energy output of a wind turbine is strongly dependent on the average wind speed at the turbine location. The average wind speed depends on the geographical location, the hub height, and the surface roughness. Hills and mountains also affect the wind flow, and therefore steep terrain requires more complicated models to predict the wind resource, while the local wind conditions in flat terrain are normally dominated by the surface roughness. Also, local obstacles like forest and, for small turbines, buildings and hedges reduce the wind speed as do wakes from neighbouring turbines. Furthermore, factors like the high altitude range (with various locations being above 2000m) and thin air at these higher altitudes, need to be accounted for in the wind turbine selection and design.

The Eastern part of Ethiopia has a good wind resource (low to medium-wind sites). An annual wind speed of 6-7 m/s at 100m above ground (low to medium-wind site) is usually considered the minimum threshold for the feasibility of a wind project (alternatively, power densities around 250 W/m^2 at hub height). Some areas in the Eastern part of Ethiopia are endowed with a wind resource greater than 9 m/s at 100m height above ground (Figure 10). These areas are characterized by a reasonably flat, clear terrain and little vegetation.

Table 4 reports wind speed data at hub height (where available) for the existing and under development wind projects in Ethiopia.

Table 4: Wind speed and hub height of existing wind projects in Ethiopia.

Site	Capacity [MW]	Hub height [m]	Wind speed at hub height [m/s]	Investment Cost [M$/MW]	Status
Aysha	120	80	8.9	2.14	Committed
Adama1	51			2.29	Existing
Adama2	153	70	9.5	2.25	Existing
Ashegoda	120	70-80	8.5	2.08	Existing
Assela	100	84	8.4	1.44	Committed

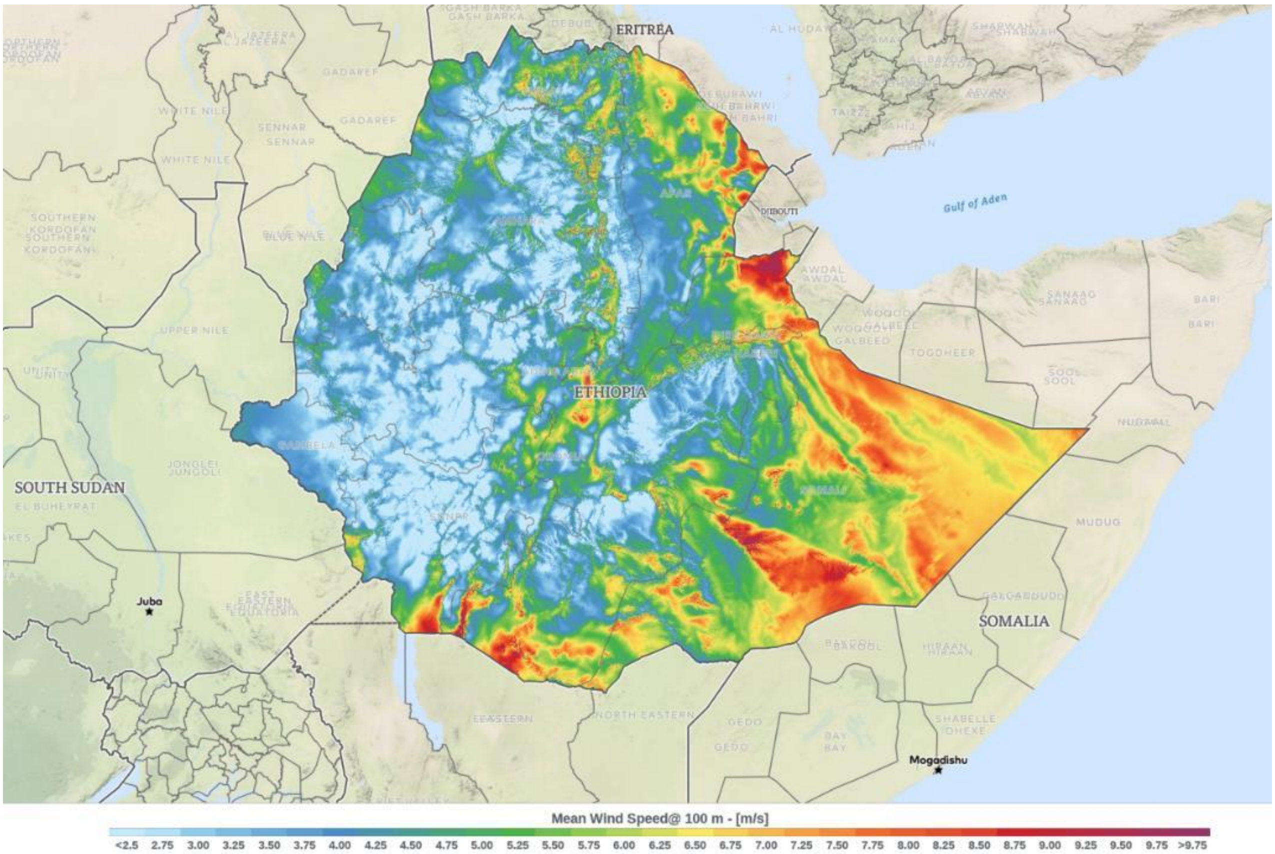


Figure 10: Wind resource at 100m above ground level in Ethiopia (ref. 23).

Output

Electricity. The relationship between input (wind speed) and output (electricity) is given by power curves, which are part of the manufacturer's catalogue. An example is shown in Figure 11, where the cut-in, rated and cut-out speeds are also indicated.

Wind measurements for at least 1 year should be taken to predict generation at a site, along with considering its validity in the long-term. Measurements should be at the same height above ground as the predicted nacelle height.

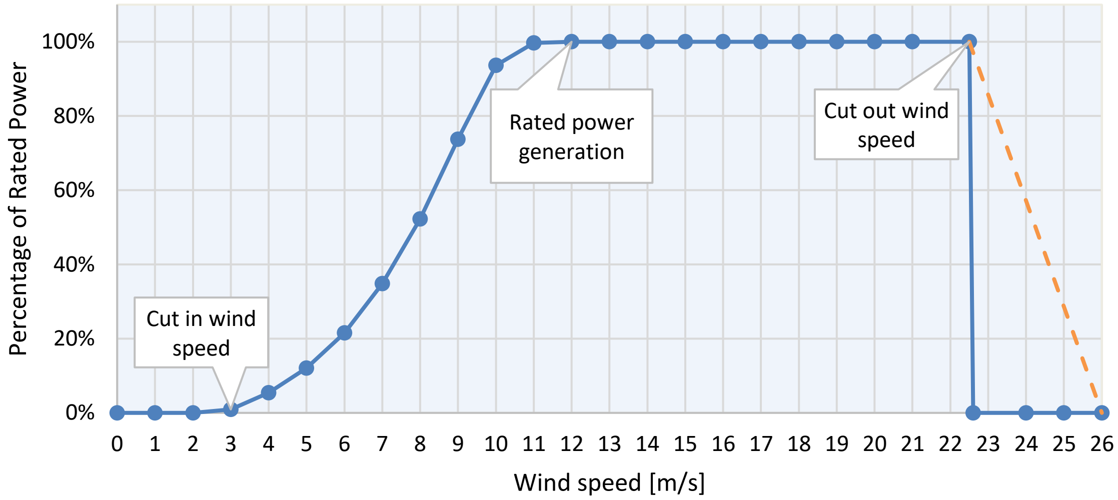


Figure 11: Power curve for a typical wind turbine. Instead of the traditional cut-out curve, some turbines have a gradual cut-out curve (dashed line).

Typical capacities

Wind turbines can be categorized according to nameplate capacity. At the present time, new onshore installations are in the range of 2 to 6 MW (ref. 16).

Two primary design parameters define the overall production capacity of a wind turbine. At lower wind speeds, the electricity production is a function of the swept area of the turbine rotor. At higher wind speeds, the power rating of the generator defines the power output. The interrelationship between the mechanical and electrical characteristics and their costs determines the optimal turbine design for a given site.

The size of wind turbines has increased steadily over the years (Figure 12). Larger generators, larger hub heights and larger rotors have all contributed to increase the electricity generation from wind turbines. Lower specific power improves the capacity factor (that is, the yearly energy yield), since power output at wind speeds below rated power is directly proportional to the swept area of the rotor (see above).

However, installing large onshore wind turbines requires well developed infrastructure to be in place, to transport the big turbine structures to the site. If the infrastructure is not in place, the installation costs are much higher, and it might be favourable to invest in smaller turbines that the existing infrastructure can manage. However, there are cases where such infrastructure is built together with the project, e.g., Vestas' Lake Turkana Wind Power project in Kenya where small turbines (52 m) were used (ref. 15).

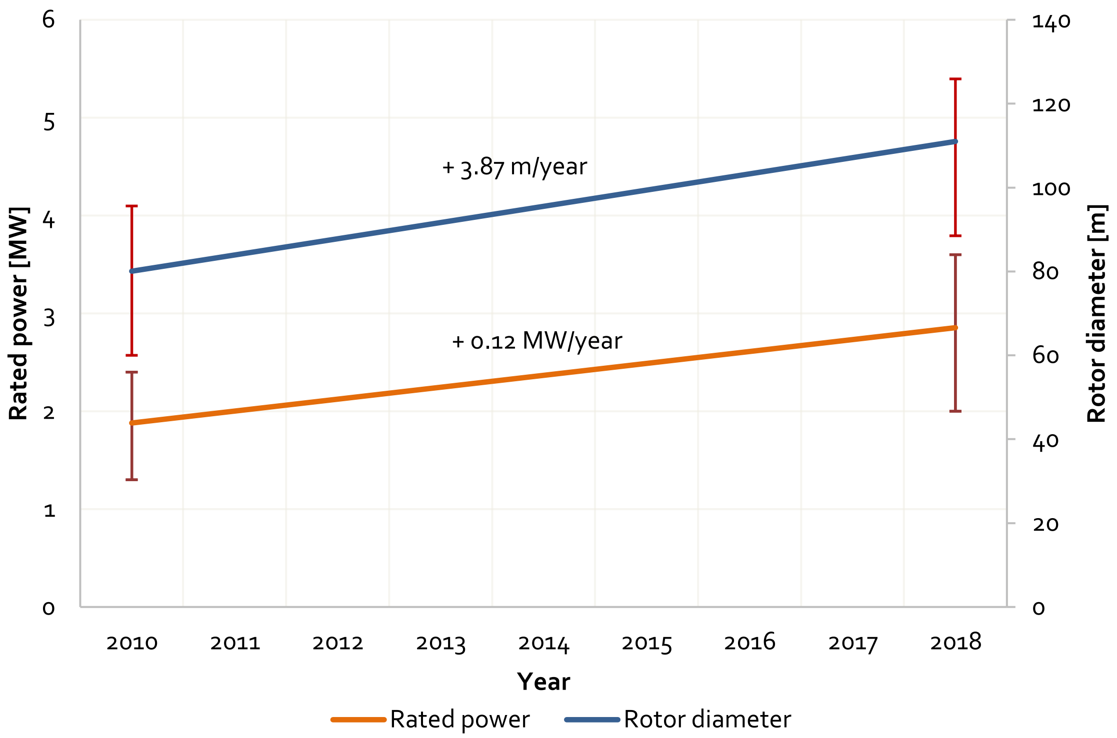


Figure 12: Evolution of rotor diameter and rated power in 2010-18 (world figures). Source: own elaboration from ref. 12.

Ramping configurations

Electricity production from wind turbines is highly variable because it depends on the actual wind resource available. Therefore, the ramping configurations depend on the weather situation. In periods with low wind speeds (less than 4-6 m/s) wind turbines cannot offer ramping regulation, except for voltage regulation.

With sufficient wind resources available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always ramp down and - in many cases - also up, provided that the turbine is running in power-curtailed mode (i.e., with an output which is deliberately set below the potential output based on the available wind resource).

In general, a wind turbine will run at maximum power according to the power curve and up ramping is only possible if the turbine is operated at a power level below the actual available power. This mode of operation is technically possible, and, in many countries, turbines are required to have this feature. However, it is rarely used since the system operator will typically be required to compensate the owner for the reduced revenue (ref. 2).

Generation from wind turbines can be regulated down for grid balancing. The start-up time from no production to full operation depends on the wind resource available.

Some types of wind turbines (DFIG and converter based) also have the ability to provide supplementary ancillary services to the grid such as reactive power control, spinning reserve, inertial response, etc.

Advantages/disadvantages

Advantages:

- No emissions of local pollution from operation.
- No emission of greenhouse gasses from operation.
- Stable and predictable costs due to low operating costs and no fuel costs.
- Modular technology allows for capacity to be expanded according to demand, avoiding overbuilds and stranded costs.
- Short lead time for construction compared to most alternative technologies.
- Land required for wind farms can be used for activities like agriculture between the towers.

Disadvantages:
- Land use:
  - Wind farm construction may require clearing of forest areas.
  - High population density may leave little room for wind farms.
- Variable power production
- Due to the uncertainty of future wind speed forecast of generation can be a challenge. These forecasts are needed for better operation and planning of the power grid.
- Moderate contribution to firm capacity provision compared to thermal power plants.
- Need for regulating power.
- Visual impact and noise.
- Endangerment of animal species affected by the turbine/farm erection.

Environment
Wind energy is a clean energy source. The visual impact of wind turbines is an issue that creates some controversy, especially since onshore wind turbines have become larger. Another issue in some cases is flickering, which is generally managed through a combination of prediction tools and turbine control. Turbines may in some cases need to be shut down for brief periods when flickering effect could affect neighbouring residences. However, this is not an issue in remote areas.

Noise is generally dealt with in the planning phase by accounting for sufficient distance between housing areas and the wind turbines installed. Allowable sound emission levels are calculated based on allowable sound pressure levels at neighbours. In some cases, it is necessary to operate turbines at reduced rotational speed and/or less aggressive pitch setting to meet the noise requirements. However, there is a need to have regulations for the noise levels, which is not the case in most countries.

The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. However, most wind projects require an environmental assessment to understand the overall impact linked to the erection and operation of the turbine. In addition, the mining and refinement of rare earth metals used in permanent magnets is an area of concern (ref. 3,4,5). Life-cycle assessment (LCA) studies of wind farms have concluded that environmental impacts come from three main sources:
- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled (~96% of the weight of the wind turbine generator)
- hazardous waste from components in the nacelle.
- greenhouse gases (e.g., CO_2 from steel manufacturing and solvents from surface coatings).

However, it should be noted that wind energy has a significantly lower energy and carbon payback time (less than a year) as compared to most other electricity generation technologies. Energy payback is the period of time for which a wind turbine needs to be in operation before it has generated as much electricity as it consumes in its lifecycle. Carbon payback is the period of time for which a wind turbine needs to be in operation before it has, by displacing generation from fossil-fuelled power stations, avoided as much carbon dioxide as was released in its lifecycle.

Area requirements

The *direct area* is the area covered by the installations (turbines and access roads). The *total area* is the areas of the field. Wind farms can cover a large area. With a distance between turbines of 6-8 times the rotor diameter, the total area of a wind farm is in the order of 0.2 m^2/W. However, after installation more than 90% of the total area can still be used, e.g., for agricultural purposes. This gives a direct area < 0.02 m^2/W.

The NREL report (ref. 18) features a detailed discussion on challenges related to defining the footprint areas. Values for specific projects depend on turbine capacity and wind resources.

Employment

In India, a total instalment of 22,465 MW onshore wind power, as of 2014, has resulted in an employment of around 48,000 people, meaning that an installed MW of wind power generates around 2.1 jobs locally in onshore wind power (ref. 7, 8). The 300 MW Lake Turkana onshore wind project in Kenya is employing 1,500 workers during construction and 150 workers at the operational state, of whom three quarters will be from the local communities, thus generating 0.5 long-term jobs per MW (ref. 14).

Figure 13 illustrates the distribution of direct employment in different industries related to wind power in Europe. Figures almost double when considering indirect employment. Service providers include transportation of equipment, engineering and construction, maintenance, research and consultancy activities, financial services.

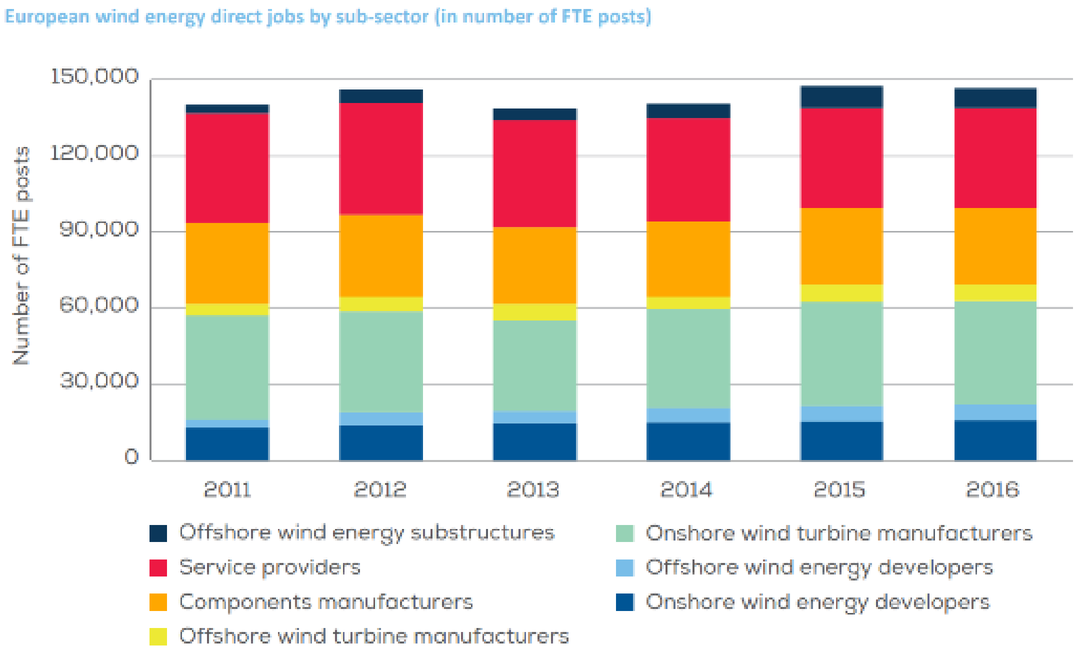


Figure 13: Direct employment by type of company based on wind farm projects in Europe (ref. 6).

Research and development

The wind power technology is a commercial technology, but subject to sizeable technical improvements and cost decreases (category 3). The R&D potential is linked to (ref. 3, 9):

- Reduced investment costs resulting from improved design methods and load reduction technologies.
- More efficient methods to determine wind resources, incl. external design conditions, e.g., normal, and extreme wind conditions.
- Improved aerodynamic performance.
- Reduced O&M costs resulting from improvements in wind turbine component reliability.
- Development in ancillary services and interactions with the energy systems.
- Improved tools for wind power forecasting and participation in balancing and intraday markets.
- Improved power quality. Rapid change of power in time can be a challenge for the grid.
- Noise reduction. New technology can decrease the losses by noise reduced mode and possibly utilize good sites better, where the noise sets the limit for number of turbines.
- Storage technologies, which can improve value of wind power significantly but is expensive at present.

Investment cost estimation

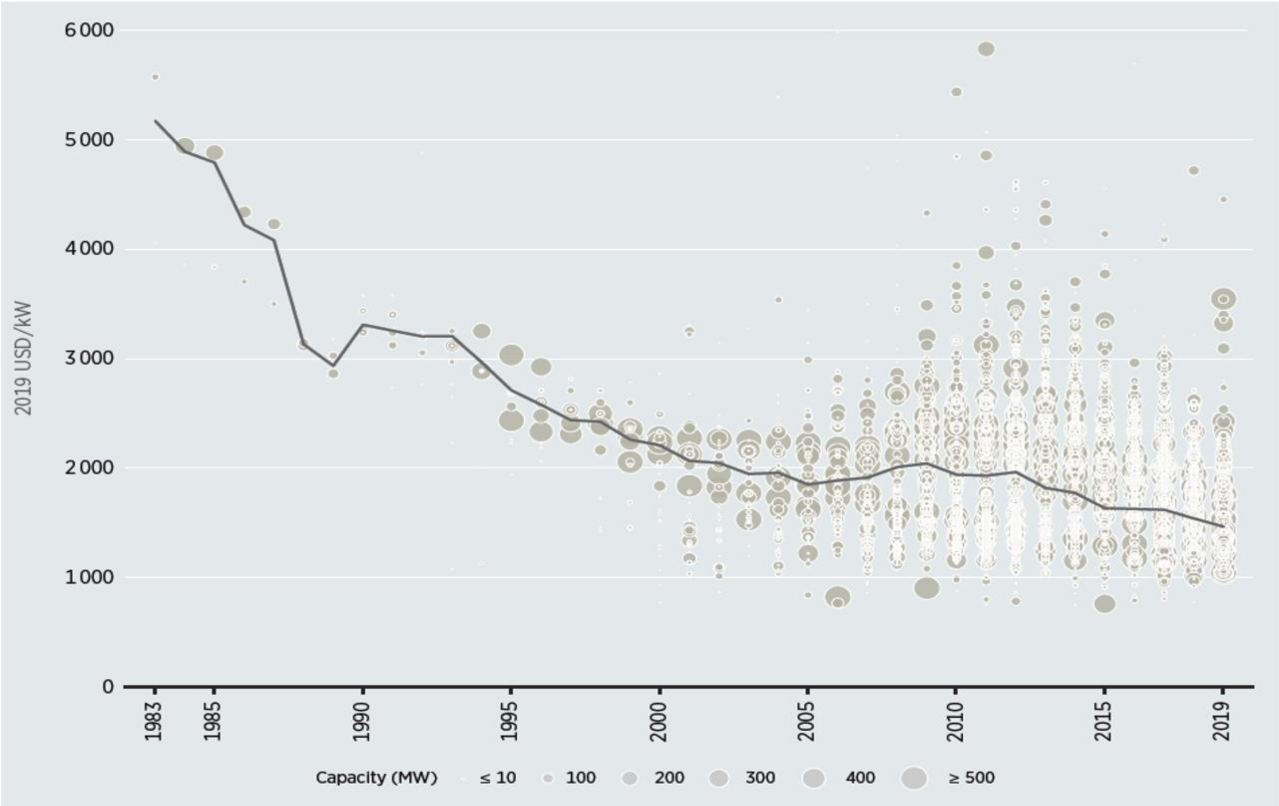
Data from onshore projects in Denmark (2013 and 2014 data) show that the average investment costs for these projects are approximately 1.4 M$/MW (ref 10). In Germany, average reported costs for 2012 are higher, approx. 1.8 M$/MW (ref. 11) and probably more representative for the Ethiopian context because the wind resource in Germany is moderate on many locations and therefore better suited for low wind speed turbines. For updated investment costs, specific power, and wind speeds in selected countries, see the IEA website[1].

Data from IRENA (ref. 18) indicate total investment costs for onshore wind power of 1.497 M$/MW in 2018 – based on an extensive database.

In the US, average investment cost for onshore wind was just below 2.0 M$/MW in 2012, but since then, costs have decreased to around 1.7 M$/MW by 2015 (ref. 12). According to IRENA, reported costs for India and China have been lower for the period 2013-2014, at around 1.3-1.4 M$/MW (ref. 13).

In the report Forecasting Wind Energy Costs and Cost Drivers, a non-country specific mean cost for onshore wind of 1.78 M$/MW is provided, representing a mean value for 2014 reported by global wind experts (ref 15). Note that the reported investments above include project development and grid connection (Balance of System, BOS).

[1] Link to the IEA data viewer.



Source: IRENA Renewable Cost Database.

Figure 14: Total installed costs of onshore wind projects and global weighted average, 1983-2019 (ref.18).

Further technological development and cost reductions by global wind turbine manufacturers can be expected to reduce investment costs further beyond 2020. Recent development with results of technology-neutral auctions in Mexico (2017: 20.6 $/MWh, total payment) and Denmark (2018: 3.5 $/MWh premium on top of market price) confirm the development towards a very low-cost.

On the other hand, the experience with wind turbines in Ethiopia is limited, which is likely to add to costs compared to countries with large-scale deployment. As of 2020, a local manufacturing industry is not established in the country. A local company signed a contract with DEC (Development Expertise Center) to deliver 8 turbine towers for the Aysha wind site. The company's capability to fulfil its commitment was assessed during the Assela feasibility study.

The Aysha and Assela wind farms, currently under development, are estimated to require an average specific investment of around 1.79 million $/MW.

Onshore wind turbines technology development continues at a considerable pace and the cost of energy has continued to drop. While the price and performance of today's onshore wind turbines are well-known, future technology improvements, increased industrialization, learning in general and economies of scale are expected to lead to further reductions in the cost of energy. The annual specific production (capacity factor/full load hours) is expected to continue to increase. The increase in production is mainly expected to be due to lower specific power, but also increased hub heights, especially in the regions with low wind, and improvement in efficiency within the different components is expected to contribute to the increase in production.

Investment costs [$MUSD_{2019}$/MW]		2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**1.63**	**1.21**	**1.02**
Ethiopian data	Local estimate for planned projects (Source: EEP)			1.2[1]	
International data	IEA WEO 2019 (average of India and China)	1.19			1.16 *(2040)*
	Danish technology catalogue		1.25	1.16	1.08
	IRENA (various)	2.37	-	1.08	0.83
	NREL ATB		2.50	1.80	1.64
	UK Government (DECC)			1.43	1.31
Projection	Learning curve – cost trend [%]	-	100%	85%	72%

[1] *Based on average estimated costs from feasibility and pre-feasibility studies for projects that are expected to be commission after 2024.*

While the average estimated investment cost for future projects is relatively lower, the final projections are empirically adjusted to account for the fact that these values are based on estimates from feasibility studies, and these projects are expected to be realised in the later part of this decade. The 2020 value is considered a little higher as existing projects in the African region have been realised at much higher cost in countries with a more developed wind supply chain (ref. 22). Taking this adjusted value as the starting point for 2020 the learning curve trend is applied.

Additionally, what also needs to be noted is that with time various technological and geographical factors contribute to the cost development. With increased research and development and improvement in technology the costs for the turbine can also go up. Overall, it is expected that with time there will be turbines with higher power ratings (MW), increased hub height and rotor diameter. This would result in lower specific power (W/m^2), but overall increase in capacity factor which will lead to reduced LCOE values for projects. Therefore, taking such factors into consideration it can be expected that in 2050 the investment cost reduction may be less than the one projected by the learning curve trend alone. Usually, it is expected that in the future the local or regional costs start aligning more or less with the global costs.

As discussed in the introductory section of this chapter, wind turbines are also dependent upon the rated wind speeds they are built for. The investment cost varies according to the different wind speed levels (Table 5). For the African context, the estimated data according to average wind speed levels is presented below for the year 2020.

Table 5: Investment cost estimate and characteristic values according to wind class

Characteristic	High wind, HW	Medium wind, MW	Low wind, LW
Power rating [MW]	4	3.45	3
Specific power [W/m^2]	315	275	245
Investment costs [$MUSD_{2019}$/MW]	1.41	1.63	1.88

For Ethiopia, as previously discussed, most sites can be characterised as medium or low wind sites, making the respective values most relevant.

Examples of current projects

- The Aysha wind site under construction has a total investment cost of 257M$ for a 120MW farm, which equals 2.14M$/MW.
- The Assela wind farm is to commence operations soon. Its investment cost is 144M$ for a 100MW farm, which equals 1.44M$/MW.

Other wind projects commissioned in recent years are:

- The Ashegoda wind farm, constructed in 2013. The total investment cost was 250M$ for a 120MW farm, which equals a per MW cost of 2.08 M$/MW.
- The Adama 1 wind farm, constructed in 2012. The total investment cost was 117M$ for a 51MW farm, which equals a per MW cost of 2.29 M$/MW.
- The Adama 2 wind farm, constructed in 2015. The total investment cost was 345M$ for a 153MW farm, which equals 2.25M$/MW.

Based on the AWPG measuring campaign program, there are more projects sites under consideration and which includes Aysha III, Aysha I, Debre Birhan, Adigala, Dire Dawa, Gode, Tulu Guled, Mega, Sela Dengay and Deday. Other future projects may include: Asela-I, Asela-II, Sure, Idabo, Mekele, Kebri Beyah, May Mekdan, Assosa Bambasi. Overall, the average estimated investment cost for some of these projects ranges from 0.95 to 1.49 MUSD19/MW, with total capacity of ~3.5 GW estimated to be commissioned between 2023-2025.

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The description in this chapter is to a great extent from the Danish Technology Catalogue "*Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following sources are used:

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23. Map obtained from Global Wind Atlas 3.0, https://globalwindatlas.info

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Wind power - Onshore								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3.5	4.0	6.0	3.0	4.0	5.0	7.0		1,3
Generating capacity for total power plant (MWe)	105	120	150						1
Electricity efficiency, net (%), name plate	100	100	100					A	
Electricity efficiency, net (%), annual average	100	100	100						
Forced outage (%)	2.5%	2.0%	2.0%						
Planned outage (weeks per year)	0.16	0.16	0.16	0.05	0.26	0.05	0.26		3
Technical lifetime (years)	25	30	30	20	35	25	40		3
Construction time (years)	2.0	2.0	1.5						1
Space requirement (1000 m^2/MWe)	14	14	14						1
Additional data for non thermal plants									
Capacity factor (%), theoretical	35	36	37	20	45	20	45	B	
Capacity factor (%), incl. outages	34	35	36						
Ramping configurations									
Ramping (% per minute)	-	-	-					F	
Minimum load (% of full load)	-	-	-					F	
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.63	1.21	1.02	1.22	2.04	0.77	1.28	D,G	1,6,7
- of which equipment	65%	65%	65%					C	2, 3
- of which installation	35%	35%	35%					C	2, 3
Fixed O&M ($/MWe/year)	46,000	39,100	33,120	25,000	70,000	25,000	60,000		4
Variable O&M ($/MWh)	0	0	0						4
Start-up costs ($/MWe/start-up)	0	0	0						

References:

1 Data about local cases.(source EEP and consultant)
2 IRENA (2015). Renewable Power Generation Cost in 2014
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4 IEA Wind Task 26, 2015, "Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the EU, and the USA: 2007–2012".
5 Vestas data provided by the Sales Division for the Asian Pacific.
6 IEA, World Energy Outlook, 2019.
7 Learning curve based forecast of technology costs. Ea Energy Analyses, 2020

Notes:

A The efficiency is defined as 100%. The improvement in technology development is captured in capacity factor, investment cost and space requirement.

B The capacity factor provided represent an average of good low wind speed locations.

C Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.

D The IEA expects approximately a doubling of the accumulated wind power capacity between 2020 and 2030 and 4-5 times more by 2050 compared to 2020. Assuming a learning rate of 12.5 % per annum this yields a cost reduction of approx. 15 % by 2030 and approx. 28 % by 2050.

E Uncertainty (Upper/Lower) is estimated as +/- 25%.

F With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).

G For 2020, uncertainty ranges are based on cost spans of local cases and an uncertainty range of +/- 25%

3. SOLAR PHOTOVOLTAICS

Brief technology description

Solar energy converts energy from sunlight to electricity with the help of photovoltaic panels consisting of solar cells. A solar cell is a semiconductor component that generates electricity when exposed to solar irradiation. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane to obtain a mechanical ridged and weathering protected solar module. The photovoltaic (PV) modules are typically 1-2.5 m^2 in size and have a power density in the range 160-500 Watt-peak pr. m^2 (Wp/m^2). They are sold with a product warranty of typically ten to twelve years, a power warranty of minimum 25 years and an expected lifetime of more than 30-35 years depending on the type of cells and encapsulation method.

PV modules are characterised according to the type of absorber material used:

- Crystalline silicon (c-Si); the most widely used substrate material is made from purified solar grade silicon and comes in the form of mono- or multi-crystalline silicon wafers. Currently more than 95 pct. of all PV modules are wafer-based divided between multi- and mono-crystalline. This technology platform is expected to dominate the world market for decades due to significant cost and performance advantages (ref. 1).
- Passivated Emitter and Rear Cell (PERC); this is a more recent advancement in solar cell technology where mono-crystalline silicon cell architecture is modified to have a passivation layer at the back of the cells. The additional layer allows for the solar radiation, that has not been absorbed, to reflect and allow for a second attempt for absorption by the cell. This layer improves the cell efficiency and reduces cell heating.
- Tandem/hybrid cells; Tandem solar cells are stacks of individual cells, one on top of the other, that each selectively convert a specific band of light into electrical energy, leaving the remaining light to be absorbed and converted to electricity in the cell below.
- Thin film solar cells; where the absorber can be an amorphous/microcrystalline layer of silicon (a-Si/µc-Si), Cadmium telluride (CdTe) or Copper Indium Gallium (di)Selenide (CIGS). These semiconductor materials are deposited on the top cover glass of the solar module in a micrometre thin layer. Tandem junction and triple junction thin film modules are commercially available. In these modules several layers are deposited on top of each other to increase the efficiency (ref. 1).
- Monolithic III-V solar cells; that are made from compounds of group III and group V elements (Ga, As, In and P), often deposited on a Ge substrate. These materials can be used to manufacture highly efficient multi-junction solar cells that are mainly used for space applications or in Concentrated Photovoltaic (CPV) systems (ref. 1).
- Perovskite material PV cells; Perovskite solar cells are in principle a Dye Sensitized solar cell with an organo-metal salt applied as the absorber material. Perovskites can also be used as an absorber in modified (hybrid) organic/polymer solar cells. The potential to apply perovskite solar cells in a multi-stacked cell on e.g., a traditional c-Si device provides interesting opportunities (ref. 1).

One of the emerging trends in the solar PV space is innovative advancements of PV module technologies (ref.7):

- Bifacial solar cells; Bifacial cells can generate electricity not only from sunlight received on their front, but also from reflected sunlight received on the reverse side of the cell. This technology has received a boost due to the development of PERC cell architecture. Bifacial operation with PERC can potentially increase cell efficiency by 5-20%.
- Multi-busbars; Busbars are thin metal strips on the front and back of solar cells that facilitate the conduction of DC current. While older designs have only 2 busbars on solar cells, recent

advancements have led to solar cells with 3 or more, thinner busbars. These allow higher efficiencies, reduced resistance losses, and overall lower costs.

- Solar shingles; This development is towards designing panels that look like conventional roofing materials while also being able to produce electricity like PV panels.

In addition to PV modules, a grid connected PV system also includes Balance of System (BOS) consisting of a mounting system, dc to ac inverter(s), cables, combiner boxes, optimizers, monitoring/surveillance equipment and for larger PV power plants also transformer(-s). The PV module itself accounts for less than 50% of the total system costs (and this share is dropping fast), while inverters account for around 5-10%.

Solar PV plants can be installed at the transmission or distribution level (utility-scale PV or floating PV), or they can satisfy consumption locally (distributed and off-grid PV). Most PV installations are utility-scale nowadays, but the market share of distributed and off-grid PV (rooftop and industrial PV) is rising.

Floating PV

Floating solar PV refers to a solar power production installation mounted on a structure that floats on a body of water, typically an artificial basin or a lake. Floating PV normally feeds the power grid. The main advantage of floating PV plants is that they do not take up any land, except the limited surfaces necessary for electric cabinet and grid connections. The plants provide a good way to avoid land disputes. The yearly yield of floating PV units can be up over to 10% higher that of ground-mounted PV panels, thanks to a higher irradiance (albedo effect) and a milder and constant temperature not only on PV cells but also on conductors. Other reported benefits include the reduction of water evaporation and eutrophication, which limits the growth of biomass (algae) in artificial and natural basins. Floating PV can ideally be combined with hydropower plants to create a virtual hybrid plant that satisfies different load conditions (ref. 14). Moreover, floating PV can utilise existing grid connection to the hydro power plant, thereby improving the business case.

The capital cost of Floating PVs is comparable to that of land-based plants. A major part of regular maintenance is cleaning of panels to avoid reduced production due to dust coverage. With floating PVs due to the presence of water, the cleaning of panels is relatively eased. Their capacity can range from several kW to hundreds of MW in size.

Input

Global Horizontal Irradiation, GHI (direct and diffuse). The GHI hitting the modules depends on the solar resource potential at the location, including shade and the orientation of the module (both tilting from the horizontal plane and deviation from facing south).

Ethiopia has excellent solar resources all over the country, particularly in the North and in the East. The GHI ranges between 1700 and 2500 kWh/m^2, with a photovoltaic power potential reaching 2000 kWh/kWp (FLH) in the best locations (Figure 15).

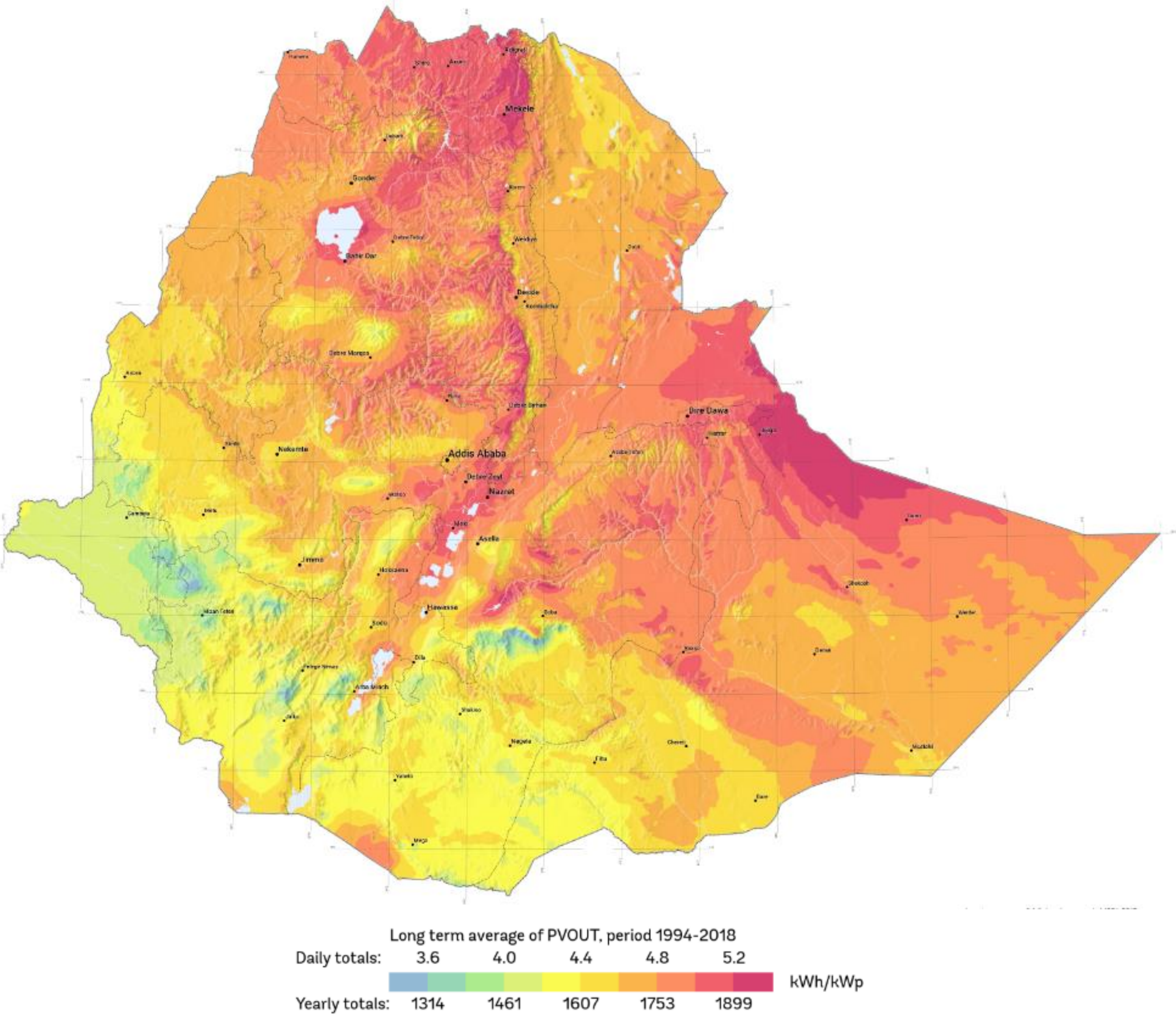

Figure 15: Full load hours (kWh/kWp) for PV in Ethiopia (ref. 24).

In general, solar panels should be tilted to capture the irradiation *normally*, that is with sun beams hitting the surface at 90° or, in other terms, with a 0° incidence angle.

The irradiation to the module can be increased even further by mounting it on a sun-tracking device.

Output

All PV panels generate direct current (DC) electricity as an output, which then needs to be converted to alternating current (AC) by use of an inverter; some panels come with an integrated inverter, so called AC panels, which exhibit certain technical advantages such as the use of standard AC cables, switchgear and a more robust PV module.

The electricity production depends on:

- The amount of solar irradiation received in the plane of the module (see above).
- Installed module generation capacity.
- Losses related to the installation site (soiling and shade).
- Losses related to the conversion from sunlight to electricity (see below).

- Losses related to conversion from DC to AC electricity in the inverter.
- Grid connection and transformer losses.
- Cable length and cross section, and overall quality of components.

Power generation capacity

The capacity of a solar module depends on the intensity of the irradiation the module receives as well as the module temperature. For practical reasons, the module capacity is therefore referenced to a set of laboratory Standard Test Conditions (STC) which corresponds to an irradiation of 1000 W/m² with an AM1.5 spectral distribution perpendicular to the module surface and a cell temperature of 25°C. This STC capacity is referred to as the peak capacity P_p (kW_p). Normal operating conditions will often be different from Standard Test Conditions and the average capacity of the module over the year will therefore differ from the peak capacity. The capacity of the solar module is reduced compared to the P_p value when the actual temperature is higher than 25°C; when the irradiation received is collected at an angle different from normal direct irradiation and when the irradiation is lower than 1000 W/m².

In practice, irradiation levels of 1000 W/m² are rarely reached, even at locations very close to the Equator. Figure 16 shows the land-weighted solar irradiance over a fixed plane in Ethiopia in 2019 (Gregorian calendar). The duration curve sorts irradiation values from the largest to the smallest. For over 3600 hours the irradiation is null (night-time) and ranging from 0 to 1070 W/m² in the rest of the year depending on time of the day, season and weather conditions.

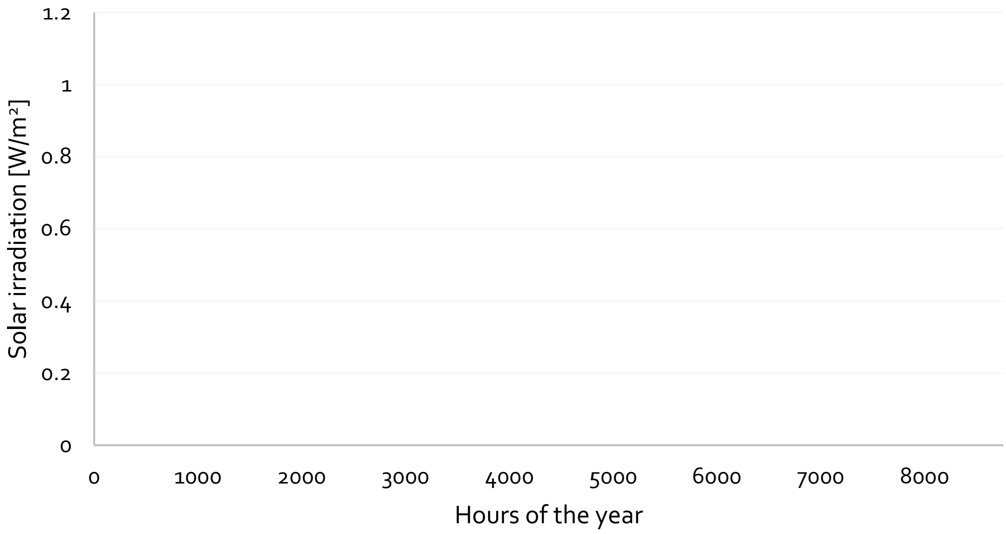

Figure 16: Land-weighted solar irradiation in Ethiopia in 2019 (duration curve). Source: renewablesninja.

Figure 17 shows the solar irradiance in an average day of March 2019 (Gregorian calendar), March being the month with the highest irradiation in Ethiopia. Values are shown for local time.

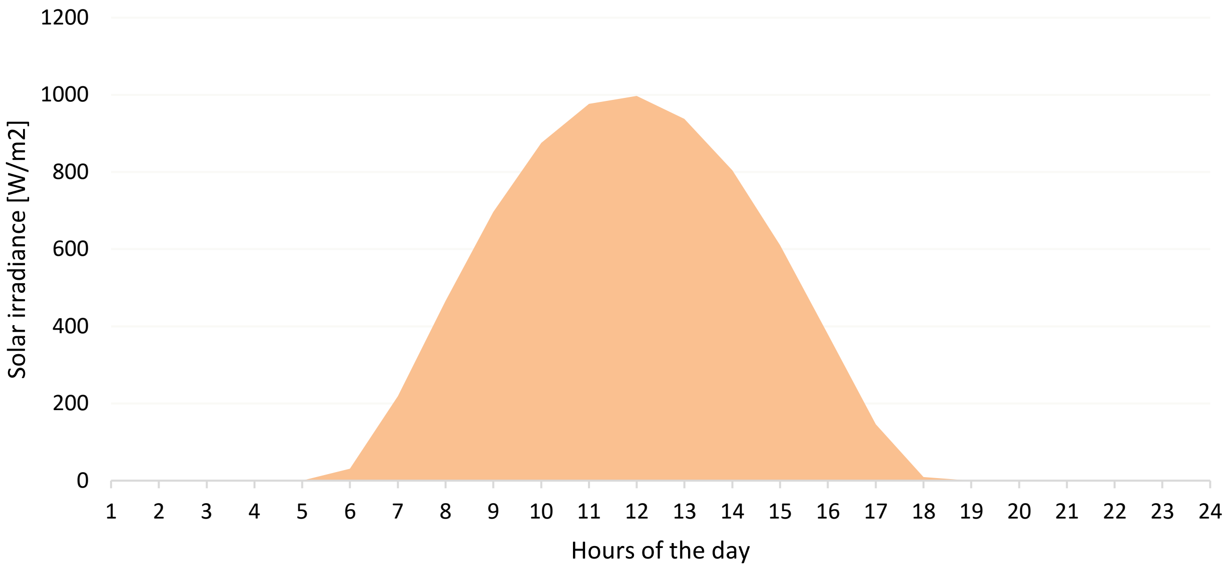

Figure 17: Average daily profile for solar irradiance over the month of March 2019. Source: renewablesninja.

Some of the electricity generated from the solar panels is lost in the rest of the system e.g. in the DC-to-AC inverter(s), cables, combiner boxes and for larger PV power plants also in the transformer.

The energy production E_{PV} [kWh] from a PV installation can be calculated as follows, with a peak capacity P_p and surface area A:

$$E_{PV} = A \cdot GHI \cdot \eta_{pre} \cdot \eta_{nom} \cdot \eta_{rel} \cdot \eta_{sys}$$

Where:

A [m²]	is the module area
GHI [kWh/m²]	is the Global Horizontal Irradiation at the location
η_{pre} [%]	represents pre-conversion losses (for shading, dirt etc.)
η_{nom} [%]	is the module nominal efficiency as specified by the manufacturer, in standard operating conditions
η_{rel} [%]	is the module relative efficiency, corrected for the ambient temperature
η_{sys} [%]	is the system efficiency, i.e. all losses incurred in cables, electronic components and plant layout.

Maintenance is required to reduce soiling especially in arid areas, or else η_{pre} can decrease consistently and lower the plant's yield. Temperature is a critical factor in PV systems, as its increase causes a drop in the modules efficiency. Finally, an optimized plant layout can reduce system losses by minimizing wiring and avoiding mutual shading among modules.

Wear and degradation

In general, a PV installation is very robust and only requires a minimum of component replacement over the course of its lifetime. The inverter typically needs to be replaced every 10-15 years. For the PV module, only limited physical degradation of a c-Si solar cell will occur. It is common to assign a constant yearly degradation rate of 0.25-0.5% per year to the overall production output of the installation. This degradation rate does not represent an actual physical mechanism. It rather reflects general failure rates following ordinary reliability theory with an initial high (compared to later) but rapidly decreasing "infant mortality", followed by a low rate of constant failures and with an increasing failure rate towards the end-of-life of the various products (ref. 11). Failures in the PV system is typical relate to soldering, cell crack or hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hailstorm and lightning (ref. 12).

Efficiency and area requirements
The efficiency of a solar module, η_{nom}, expresses the fraction of the power in the received solar irradiation that can be converted to useful electricity. Typical values for commercially available PV panels today exceed 20%, with research projects reaching over 40%, when measured at standard test conditions. The module area needed to deliver 1 kW_p of peak generation capacity can be calculated as $1/\eta_{mod}$, and equals 6.25 m^2 by today's standard PV panels.

Typical capacities
Typical capacities for PV systems are available from microwatt to gigawatt sizes. But in this context, it is PV systems from a few kilowatts for household systems to several hundred megawatts for utility-scale systems. PV systems are inherently modular with a typical module unit size of 200-350 W_p.

Commercial PV systems are typically installed on residential, office or public buildings, and range typically from 50 to 500 kW in size. Such systems are often designed to the available roof area and for a high self-consumption. Utility scale systems or PV power plants will normally be ground-mounted and typically range in size from 1 MW to 200 MW.

Note that inverter capacity may be selected smaller than the PV panel capacity. The inverter is an expensive element, and the full capacity is only used for a small amount of hours in a day. A smaller inverter leads to higher full load hours.

Ramping configurations and other power system services
The production from a PV system reflects the yearly and daily variation in solar irradiation. Modern PV inverters may be remotely controlled by grid-operators and can deliver grid-stabilisation in the form of reactive power, variable voltage and power fault ride-through functionality, but the most currently installed PV systems will supply the full amount of available energy to the consumer/grid. Without appropriate regulation in place, high penetration of PV can also lead to unwanted increases in voltage in distribution grids.

Advantages/disadvantages
Advantages:

- PV does not use any fuel or other consumable.
- PV is noiseless (except for fan-noise from inverters).
- PV does not generate any emissions during operation.
- Electricity is produced in the daytime when demand is usually highest.
- PV offers grid-stabilization features.
- PV panels have a long lifetime of more than 30 years and PV panels can be recycled.
- PV systems are modular and easy to install.
- Operation & Maintenance (O&M) of PV plants is simple and limited as there are no moving parts and no wear and tear, with the exception of tracers. Inverters must only be replaced once or twice during the operational life of the installation.
- Large PV power plants can be installed on land that otherwise are of no commercial use (landfills, areas of restricted access or chemically polluted areas).

- PV systems integrated in buildings require no incremental ground space, and the electrical interconnection is readably available at no or small additional cost.

Disadvantages:

- PV systems have relatively high initial costs and a low capacity factor.
- Only produce power when there is sun, meaning regulating power or storage is necessary.
- The space requirement for solar panels per MW is significantly more than for thermal power plants.
- The output of the PV installation can only be adjusted negatively (reduced feed-in) according to demand as production basically follows the daily and yearly variations in solar irradiation.
- Materials abundancy (In, Ga, Te) is of concern for large-scale deployment of some thin film technologies (CIGS, CdTe).
- Some thin film technologies do contain small amounts of cadmium and arsenic.
- The best perovskite absorbers contain soluble organic lead compounds, which are toxic and environmentally hazardous at a level that calls for extraordinary precautions.
- Forecasting power output of solar power plants is difficult due to the uncertainty of solar irradiation input
- The solar power potential often concentrates in some certain areas and may require increased transmission capacity.
- Solar power is non-inertia so could not support frequency control as traditional power plants.
- The efficiency of solar PVs is relatively low compared to the efficiency of other renewable energy sources.
- PV panels are fragile and can be damaged relatively easily.

Environment

The energy payback time of a typical crystalline silicon PV system in Southern Europe is 1.25 years. Energy payback is the period of time for which a solar PV plant needs to be in operation before it has generated as much electricity as it consumes in its lifecycle.

The environmental impacts from manufacturing, installing and operating PV systems are limited. The main materials used to produce PV panels include glass, plastic, aluminium, silicon and various metals in small quantities. The breakdown of the main materials in the two most common types of modules (crystalline silicon and thin film) can be visualised in Figure 18. Furthermore, the modules may contain small amounts of lead and thin film modules especially, may contain small amounts of cadmium and arsenic.

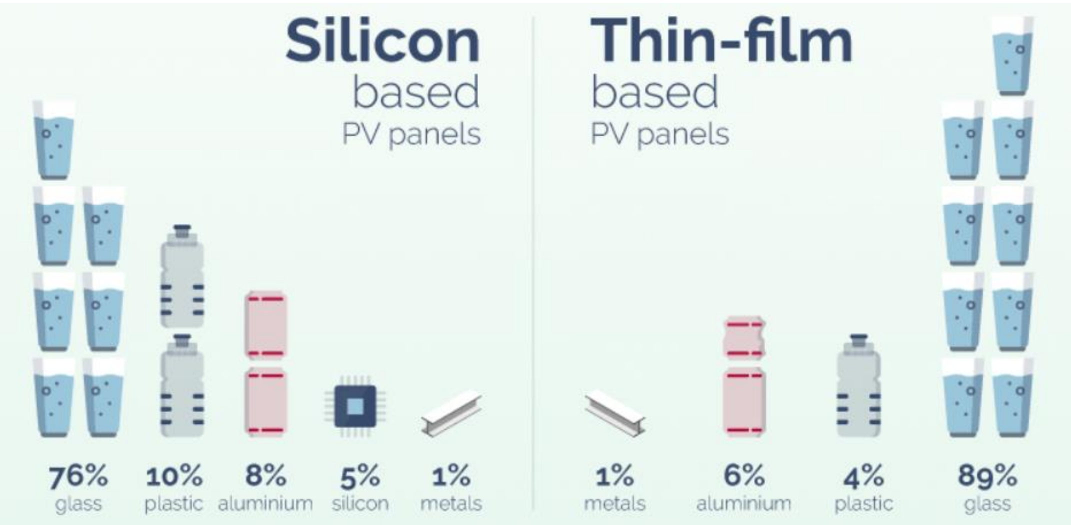

Figure 18: Main materials in a silicon based and thin film solar pv panel. (ref. 15)

With the increasing installations of PV panels, their end-of-life treatment and waste management are increasingly important topics of discussion. According to a study by IRENA, reduction of wastes can begin at the manufacturing stage itself, where it is shown that, driven by research on the PV components, material savings and panel efficiencies will drive a reduction in materials use per unit of power and the use of potentially hazardous substances (Figure 19) (ref. 16). Additionally, improved panel quality would also lead to a reduction of failures and therefore waste production during the lifetime.

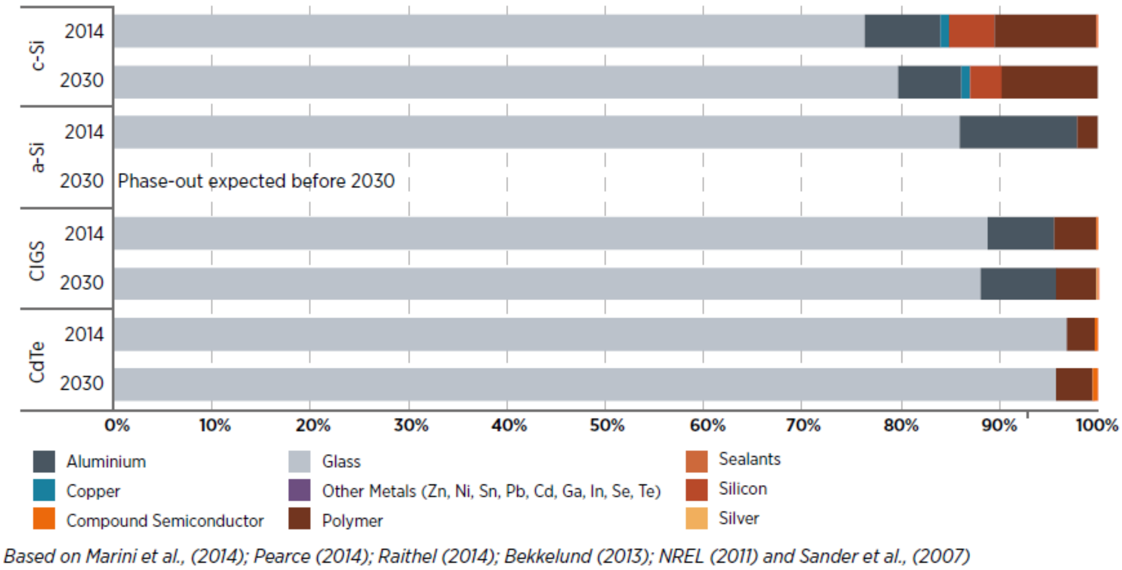

Figure 19: Evolution to 2030 of materials used for different PV panel technologies as a percentage of total panel mass (ref.16).

As for the end-of-life of the panels, it is estimated that ~96% of the materials can either be reused or recycled with proper treatment (ref. 15). The different types of processes are represented in the flow chart shown in Figure 20. Furthermore, a study estimated that using the full recovery end-of-life photovoltaic project (FRELP) method, the private cost of end-of-life management of the crystalline silicon PV module is USD 6.7/m^2 and much of this cost is from transporting (USD 3.3/m^2), while the actual recycling process (the cost of consumed materials, electricity, or the investment for the recycling facilities) is very small (USD 0.3/m^2) (ref 18). Further, it was found that the external cost of PV end-of-life management is very similar to the private cost (USD 5.2/m^2). It was also estimated that the total economic value of the recycled materials from c-Si PV waste is USD 13.6/m^2. This means that when externality costs are not considered, the net benefit of recycling is USD 6.7; when the externality cost of recycling is considered, there is still a net benefit of USD 1.19 per m^2 (ref. 18). While these are just estimated costs, they give a representative indication as to the feasibility of reuse and recycle of materials from PV panels. Moreover, the revenues from second-life or reused products also need to be considered.

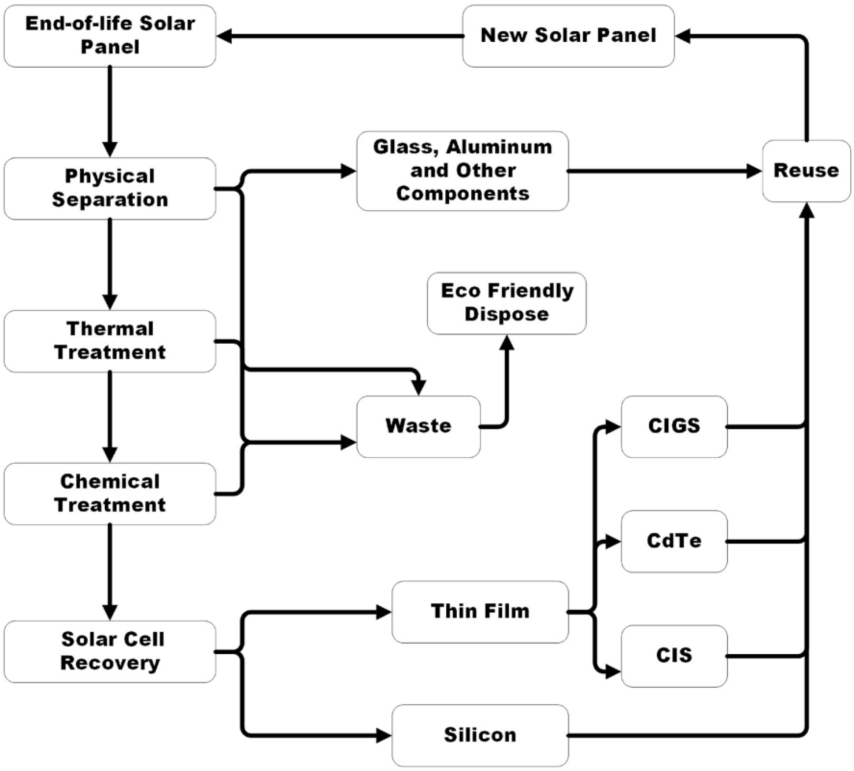

Figure 20: Different types of solar PV recycling processes (ref. 17).

While there is continuous research on-going in this area, and an increasing need for deployment of end-of-life management solutions, a major catalyst to the process would be to establish strong regulatory requirements. As of now, despite a significant discussion among organisations across the globe, about waste management from solar plants, only the European Union's WEEE directive, provides a regulatory framework whereby appropriate treatment of the waste streams is promoted. According to the WEEE directives, all electrical or electronic product manufacturers are legally accountable for proper waste management of the product no matter where manufacturing facility is located. The WEEE directive has detailed guidelines that includes collection, recovery, recycling along with environment and public health safety (ref. 19). While other countries may have some regulations regarding e-waste in general, what makes the WEEE significant is inclusion of PV module waste streams as part of this framework. Considering the expected solar PV instalments, it is of critical importance that countries, like Ethiopia, promote the setting up of end-of-life management infrastructure for solar PV waste, and support it through a regulatory framework.

Employment

As per IRENA's renewable energy jobs data solar PV is responsible for creating 3.7 million jobs globally (ref. 20). A study for renewable energy in South Africa estimates that an 86MW solar PV plant created a total of 950 jobs and employment equivalent to 3670 job years. Among these, 286 jobs were in manufacturing and development, 601 in construction and installment and 63 in operation and maintenance (ref. 21).

In Africa, a key part of the development in energy sector comes from off-grid solar projects. Based on a study, off-grid solar is estimated to create 350,000 jobs in East Africa by 2022 (ref. 22).

Research and development

The PV technology is a commercial technology, but subject to sizeable technical improvements and cost decreases (category 3). A trend in research and development (R&D) activities reflects a change of focus from manufacturing and scale-up issues and cost reduction topics to implementation of high efficiency solutions and documentation of lifetime/durability issues. R&D is primarily conducted in countries where the manufacturing also takes place, such as Germany, China, USA, Taiwan, and Japan.

Investment cost estimation

The cost of solar PV projects has decreased significantly internationally. The reported investment cost of some planned solar PV plants in Ethiopia in the near future is as follows:

- Mekele: 100 MW with an investment cost of 1.17 MUSD/MW
- Wolenchiti: 150 MW with an investment cost of 1.15 MUSD/MW
- Metema: 125 MW with an investment cost of 1.17 MUSD/MW
- Woranso: 150 MW with an investment cost of 1.1 MUSD/MW

Module prices can be observed at the PV Insights website. By September 2020, the average price of polysilicon solar modules was 0.167 USD/Watt, with prices as low as 0.15 USD/Watt. The price difference between international levels and the Ethiopian context needs to be considered.

The prices of solar PV modules have declined very significantly historically. A reduction in the order of 23% has been achieved each time the cumulative production has been doubled.

For this assessment, it is proposed applying a learning rate of 20% for approx. two-thirds of the solar PV system price, which relates to the module and the inverter. This is slightly lower than the historical observed values, but still a high learning rate compared to other technologies. Using a learning rate of 20% for the module and a future deployment of solar PV capacity as projected by the IEA, we expect PV module costs to drop by around 20-30% between 2020 and 2030 and between 40 and 50% between 2020 and 2050 (ref 5).

For the remaining one third of costs, a more moderate projection development is used, with costs falling by 0.71% p.a. between 2020 and 2030 and then by 0.52% p.a.

This leads to the cost projection, presented in Table 6, for large-scale solar PV systems, for the international price level as well as the expected level for Ethiopia. Historically, the IEA has systematically underestimated the global deployment of PV capacity. It is expected that in the long-term the price in the local context will catch up with the price internationally.

Table 6: Projected investment cost of utility-scale solar PV systems.

Mill. USD/MWp	2020	2030	2050
International price	0.67	0.53	0.41
Ethiopian price	0.98	0.7	0.51

The investment cost of a solar PV project is subject to uncertainty, especially because the technology is capital intensive. The size of the project also contributes to the specific cost, as small projects tend to require higher investments. The table below summarizes investment cost figures from relevant sources, along with the recommended values for ground-mounted PV. The solar PV industry has notched up the competitiveness of manufacturing processes in recent years, driven by a considerable R&D spending on cell materials and modules design. Future costs for solar PV in Ethiopia will depend on local content rules, import duties and the rise of a competitive manufacturing industry in the country; cost reductions will also be achieved through a more solid experience in the project development and installation stages.

Investment costs [$MUSD_{2019}$/MW]		2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**1.05**	**0.62**	**0.45**
Ethiopia data	Estimated cost for planned local cases		0.87[1]		
International data	IEA WEO 2019 (average of India and China)	0.84			0.46 *(2040)*
	Danish technology catalogue		0.48	0.34	0.27
	NREL ATB	1.17	0.99	0.61	0.50
	Lazard	1.00			
	UK Government (DECC)			0.58	0.45 (2040)
Projection	Learning curve – cost trend [%]	-	100%	71%	52%

[1] *Based on average estimated costs from feasibility and pre-feasibility studies for projects that are expected to be commission after 2023.*

The final estimates presented here still consider the learning curve trend, with the adjustment that the doubling is seen from 2023 where the local projects are expected to be realised. For estimating a base value for 2020 the trend is back tracked, under the assumption that the expected value of local projects at 0.87 MUSD/MW is realised in 2023. The final value for 2020 is comparable to costs seen in the African region (ref. 23). Furthermore, it is expected that towards 2050 the local/regional costs will eventually align with global values.

Examples of current projects

The Solar and Wind Resource Assessment (SWERA) map shows that Ethiopia has good solar resource potential in the Northern and Eastern Parts. In accordance with the produced map, the sites listed in Table 7 have been identified for future projects.

Table 7: Planned solar PV projects in Ethiopia

No	Site name	Capacity (MW)	Status	Estimated Investment (MUSD/MW)
1	Metehara solar	100	RFP stage and selection completed	0.82
2	Gad1 solar	125	RFP stage and selection completed	0.76
3	Dicheoto solar	125	RFP stage and selection completed	0.78
4	Humera	100	RFP is prepared and first stage of selection is on-going	0.81
5	Metema	125	RFP is prepared	0.87
6	Mekele	100	RFP is prepared and first stage of selection is on-going	0.85
7	Woranso	150	RFP is prepared and first stage of selection is on-going	0.71
8	Gad2	125	RFP is prepared and first stage of selection is on-going	0.88
9	Wulenchiti	150		0.82

Additionally, there are some more projects in the pipeline, which are being considered for. These include: Arbaminch, Guhala, Hamusit, Melkasedi, Meshenti, Meki/Ziway, Werota, Yirgalem and Ziquala. The project cost for some of these plants is estimated to be on average 0.97 MUSD/MW.

References

The description in this chapter is based on the Danish Technology Catalogue (ref. 1).

The following are sources used:

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24. Map obtained from Global Wind Atlas 3.0, https://globalwindatlas.info

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Utility-scale Solar PV								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity a typical power plant (MWe)	100	120	150					C	1
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	25	30	40	25	40	35	45		6
Construction time (years)	1.0	0.5	0.5	0.5	1.5	0.25	1		
Space requirement (1000 m^2/MWp)	14	14	14	13	18	13	18		6
Additional data for non thermal plants									
Capacity factor (%), theoretical	21	22	23	17	23	17	23		2
Capacity factor (%), incl. outages	21	22	23	17	23	17	23		2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.05	0.62	0.45	0.70	1.10	0.34	0.56	D,R,S	1,3,7
- of which equipment	40%	40%	40%	30%	50%	30%	50%		
- of which installation	60%	60%	60%	50%	70%	50%	70%		
Fixed O&M ($/MWe/year)	21,000	14,910	10,920	15,800	26,300	7,300	14,600	E,Q	1,3,7
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	2,000	2,000	2,000					F	2,5
DC/AC sizing factor (Wp/W)	1.10	1.10	1.10					G	
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	2,5
Performance ratio [-]	0.86	0.95	0.97					I	4
PV module conversion efficiency (%)	20.5%	23.0%	26.0%						4
Inverter lifetime (years)	15	15	15						5
Output									
Full load hours (kWh/kW)	1,950	2,100	2,150					J, L	
Peak power full load hours (kWh/kWp)	1,750	1,900	1,950					K, L	
Financial data									
PV module & inverter cost ($/Wp)									
Balance Of Plant cost ($/Wp)									
Specific investment, total system ($/Wp)									
Specific investment, total system (M$/MW)									

References:

1 Data about local cases.(source EEP)

2 Data analysed from www.renewables.ninja for multiple locations in Ethiopia

3 IEA, World Energy Outlook, 2019.

4 The Danish Energy Agency, *Generation of electricity and district heating, 2020.*

5 PVGIS © Europeen Communitees 2001-2012.

6 Learning curve based forecast of technology costs. Ea Energy Analyses, 2020

7 Ea Energy Analyses, Indonesian Technology Catalogue (2021)

Notes:

A See "PV module conversion efficiency (%)". The improvement in technology development is also captured in capacity factor, investment costs and space requirement.

B The production from a PV system reflects the yearly and daily variation in solar irradiation. It is possible to curtail solar, and this can be done rapidly.

C Listed as MWe. The MWp will be around 10% higher.

D Assumptions described in the section "Assumptions and perspectives for further development"

E Uncertainty (Upper/Lower) is estimated as +/- 25%.

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1800 kWh/m2 corresponds

G The DC/AC shown in the table equals module peak capacity divided by plant capacity. The sizing factor is chosen according to the desired utilisation/loading of the

H The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF. In Indonesia the TF factor for fixed systems is very low, adding only 0-1 % to the production.

I The performance ratio is an efficiency measure which takes the combined losses from incident angle modifer, inverter loss, PV systems losses and non-STC corrections and AC grid losses into account. The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency). PV systems losses and non-STC corrections are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables are included. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules which raise the generation by 5%.

J The number of full load hours is calculated based on the other values in the table. The formula is: Full load hours = Global horizontal irradiance * transposition factor * performance ratio.

K Also known as the specific yearly energy production (kWh/kWp) of the PV modules. This value is calculated from this formula: Peak power full load hours = 1046 * transposition factor * (1-incident angle modifier loss) * (1-PV system losses etc.) * (1-inverter loss) * (1-AC grid loss).

L Capacity factor = Full load hours / 8760.

M Current international market prices for utility scale PV systems have been estimated based on interviews with Danish developers and an assesment of the prices from Danish and Germany tenders for PV capacity in 2016 and the beginning of 2017. The forecasted internatinal price is based on estimated learning rates for the module and inverter (20 % learning rate) and balance of plant (10 % learning rate) and a projection of the accumulated PV capacity based on the IEA's 450 ppm scenario. The share that the PV module and the inverter accounts for decreases over time as the result of the higher learning rate compared to the balance of plant. Indonesian prices are assumed to be somewhat higher in the first years thereafter approaching gradually the international level.

P The "specific investment, total system per rated capacity W(AC)" is calculated as "specific investment, total system per Wp(DC)" multiplied by the sizing factor.

Q The cost of O&M includes insurance and regular replacement of inverters and land-lease. Annual O&M is estimated to be 2 % of investment cost per MWp.

R Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

S For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 17.5-22.5% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

4. CONCENTRATED SOLAR POWER

Brief technology description

The potential of solar power can be capitalized in two prominent ways, through solar photovoltaics (PV) and concentrated solar power (CSP). Solar thermal energy harnessed through a CSP can be used for electricity and heat generation. Keeping in mind the Ethiopian context, the focus here is on the electricity generation.

The power block is similar to that of conventional thermal technologies using pressurised steam to run a turbine (Rankine cycle), but the burner is replaced with a high temperature steam generator. This is essentially a heat exchanger working with a heat transfer fluid (HTF) on the primary side of the circuit, the secondary working with steam. Energy from the sun is concentrated to heat up the HTF using reflectors or lenses.

CSP technologies are grouped into different categories based on the technology used to concentrate solar rays. In general, it is possible to distinguish between *line-focusing systems* like parabolic trough (PT) and linear Fresnel plants (LFR), and *point-focusing systems* which include solar tower (ST) plants and solar dish systems.

Regardless of the specific technology, a CSP plant consists of the following two basic elements:

- A *concentrator/reflector*, which exploits optical properties of the material to redirect sun rays towards a focal point/line.
- A *receiver*, which absorbs the concentrated solar energy and heats up the collector field fluid.

Out of all CSP plants, PT and ST plants are the most common and represent the preferred choices for utility-scale power production. A description of the two is presented in the following.

- Parabolic Trough (PT) is the most commonly installed CSP system. A schematic representation of such systems is shown in Figure 21. It consists of mirrors/sheets of reflective material in a parabolic shape, allowing the sunrays to be reflected and concentrated into the focal line of the parabola. A central tube (receiver) containing a heat transfer fluid (HTF) - most often synthetic oils or molten salts - runs through the focal line. The HTF then transfers heat to the secondary circuit, with or without the presence of thermal storage in between. In many cases PT collectors are oriented North-South and have single axis tracking from East to West to maximise heat absorbed (ref. 1).

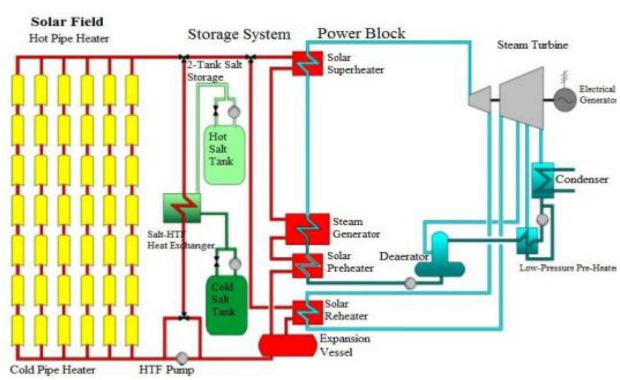


Figure 21: Parabolic trough type CSP system

- In Solar Tower (ST) systems a field of mirrors (reflectors), called heliostats, are mounted on the ground and positioned to concentrate sunrays from the sun onto a central receiver (tower). The HTF then transfers heat to the secondary circuit, with or without the presence of thermal storage in between. It is possible to have a two-axis tracking for the heliostats, to harness maximum energy from the sun (Figure 22).

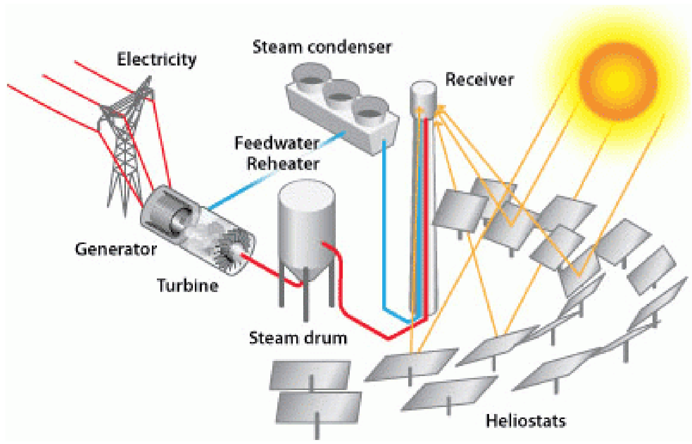


Figure 22: Solar tower type CSP system (ref. 1).

In terms of technology, most plants currently in operation (~80% global installed capacity) use the PT technology. Recent CSP projects show a different trend, with ~45% of the plants under construction being of the ST type (Figure 23). This can mainly be attributed to the ability of ST plants to achieve much higher temperatures compared to PT plants. The operating temperature for PT approximately ranges between 290-390°C, but it can reach 570°C in the solar tower concept (ref. 2). These temperatures are high enough to power steam Rankine cycles in nearly-critical conditions, thereby increasing input-to-output efficiencies. There is no physical limitation in raising temperatures further, but the additional investment needed to achieve relatively small improvements in cycle efficiency is considerable and technologies are not fully commercialised. Nevertheless, ST has the potential of being operated at temperatures close to 2000°C (ref. 3).

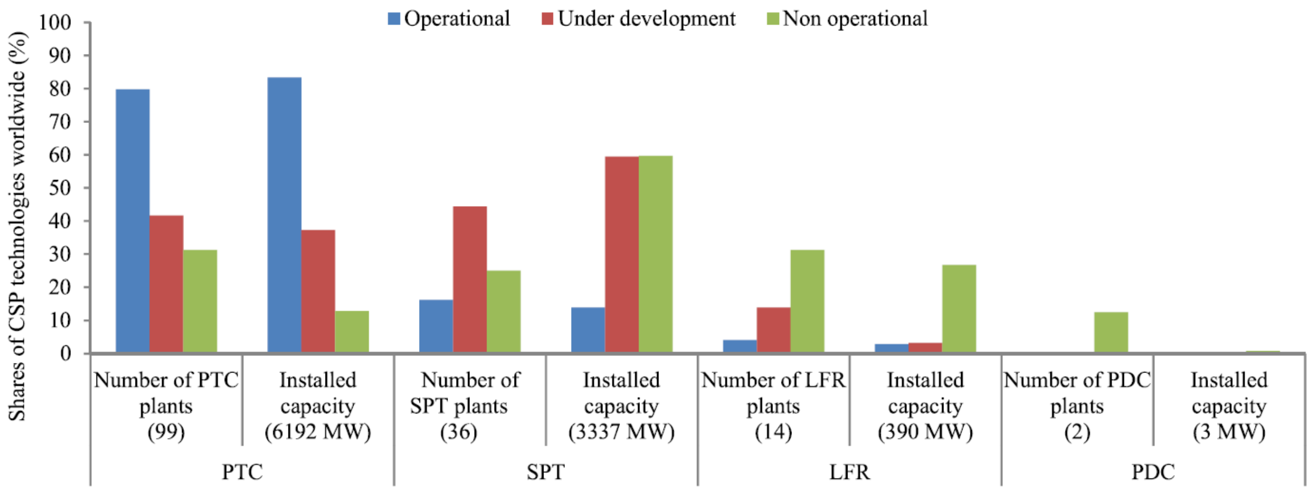
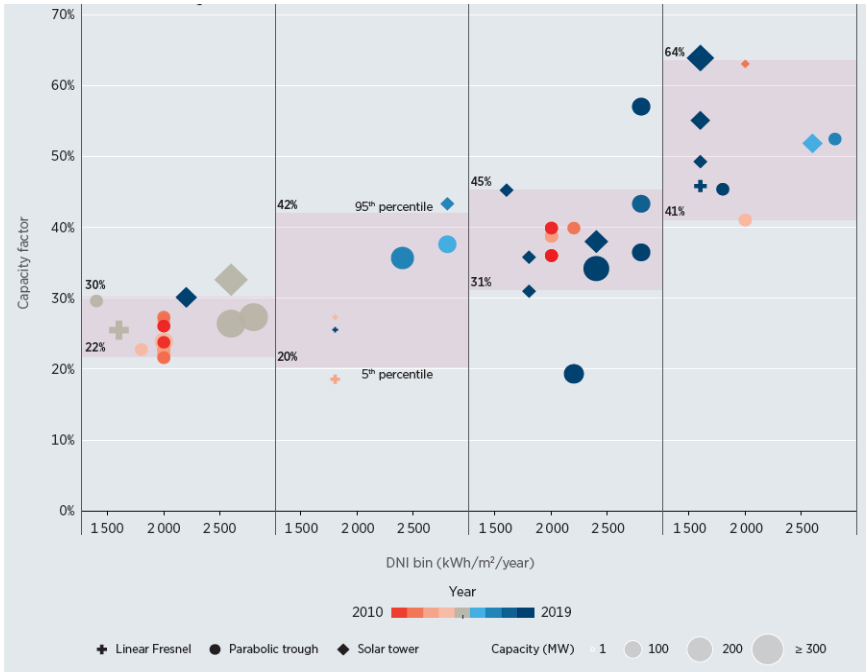


Figure 23: Shares of worldwide CSP projects by technology. While PT plants make up the far largest part of the installed capacity, ST (here SPT) plants will make up a bigger share in the future (ref 2).

In addition to the CSP collector field, most new plants include thermal energy storage. While thermal energy storage increases project costs, it allows for higher capacity factors and makes CSP less reliant on the variability of the solar resource. The most used system is the two-tank system, with sensible heat storage. It is composed of two tanks, one at a high and the other at a low temperature. The HTF (commonly molten salt) is pumped from the colder tank and is heated through the collector field. The hot fluid is then directed to the high temperature tank before it produces steam for the power cycle and is pumped back to the cold tank. Molten salt is usually made of a 60:40 ratio of sodium nitrate and potassium nitrate, a mixture with a melting point of 238°C (minimum allowed temperature of the cold tank). Usually, cold and hot tank temperatures are around 290°C and 575°C respectively (ref 4).

The advantage of having a thermal storage system is that it allows the heat stored during a day to be reused in the periods where there is no sunlight. This is especially advantageous for dispatching during the evening peak load hours. Moreover, the molten salt thermal energy storage has a high round-trip efficiency (above 90%), allowing to store heat for a long period of time with minimal losses. Figure 24 shows the influence of storage capacity on the capacity factor of the CSP plant. With respect to thermal storage availability, 55% of operational and under development projects have a storage system. Over 90% of these projects have molten-salt-based two-tank storage systems with a daily average storage capacity of 7hr (ref 2). The storage capacity in many projects across the globe goes up to 15-20 hours and long-term future applications might require one-day storage facilities to improve the project feasibility (ref. 14). It is estimated that the Atacama-1 project in Chile will have 17.5 hours of storage.



Source: IRENA Renewable Cost Database.
Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.

Figure 24: Capacity factor trends for CSP plants by direct normal irradiance, 2010-2019. Based on IRENA cost database and report on Renewable Energies Power Generation Costs in 2019 (ref 5).

The final block in the CSP process flow is the power block (Figure 25). This assembly is similar to what is seen in conventional systems. Most CSP plants are equipped with a Rankine cycle using a steam turbine. Exceptions are small plants, which can power Stirling engines. Other configurations under study use Brayton cycles for the power block.

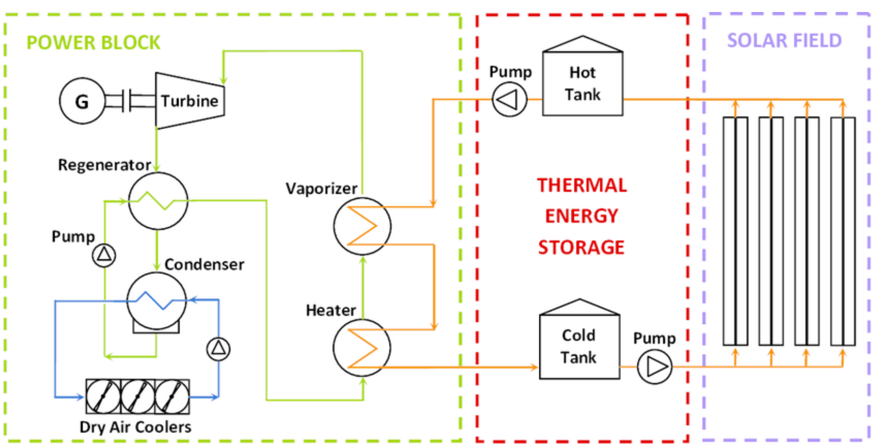


Figure 25: CSP process flow diagram (ref 6).

A factor to consider is the area required for the solar collector or heliostat field, as this influences the overall plant size, efficiency and costs. A study conducted by NREL based on solar PV (>20 MW) and CSP plants in USA, found that their capacity based weighted average total land use was 31 and 25 MWac/km^2, respectively. Furthermore, PT type CSP plants had 26 MWac/km^2, while ST type had 24 MWac/km^2 (ref 9). Heliostat fields can be very large in size and area availability can be an obstacle for the deployment of CSP projects. Compared to solar PV, CSP plants need to take advantage of economy of scale to lower the cost of generated electricity and therefore tend to require the installation of vast collector fields.

A key indicator for CSP plants is the solar multiple (SM), which is the ratio between the nominal heat output from the CSP field (MWt) and the steam turbine nominal heat input (MWt). In simpler words, the solar multiple is the actual size of the solar field relative to what would be required to reach the rated electrical capacity at the design point (ref. 7). In general, to ensure sufficient heat output from the field to run the power block at nominal capacity, SM is usually greater than 1. Additionally, if the system is equipped with heat storage, the plant area is oversized to boost the capacity factor and reduce the LCOE, causing the SM to also increase. A study conducted in Australia estimates that the SM can even go up 3.0 to 3.5 with heat storage ranging from 14 to 18 hours, to minimise the LCOE (ref. 8). Therefore, at the design stage it is critical to find the optimal field area. Land requirements can be rather tricky to estimate as they vary a lot based on solar resources of region, type of plant, storage included, visual impact etc.

Input

The input is direct normal irradiation (DNI). The minimum DNI needed for a CSP project to be cost effective is normally considered to be ~1800 kWh/m^2/year. However, there are plants operating in regions with DNI of 1500 kWh/m^2/year.

Ethiopia is endowed with a great potential for CSP. The DNI is greater than 2000 kWh/m^2 in vast areas of the country, with peaks of over 2300 kWh/m^2 in the East (Figure 26).

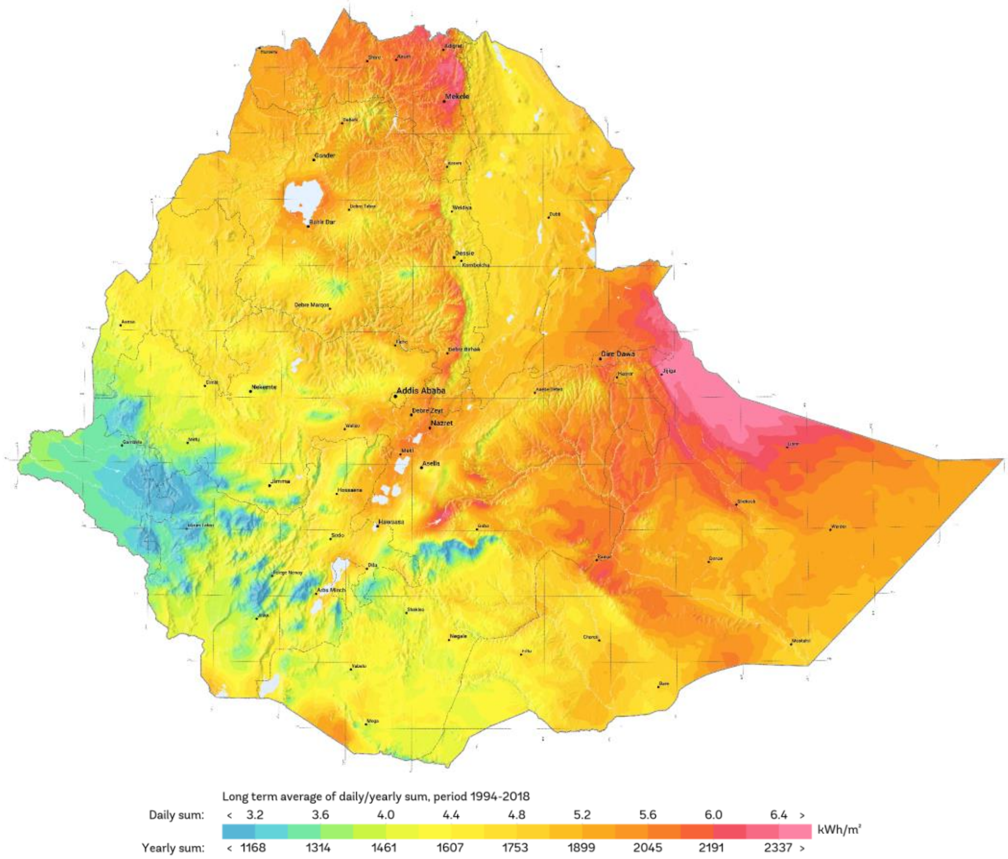


Figure 26: Annual average daily DNI for Ethiopia (ref. 18).

Output

Electricity. CSP can be also used for heat generation in selected applications (e.g., industrial processes), but this topic is not treated in this catalogue.

Typical capacities

The typical plant capacity varies a lot, based on the type of CSP plant, area availability, DNI, presence of thermal storage, system needs. According to IRENA, the estimated CSP capacity in operation in the world is 6.3 GW (ref. 12), with several projects in the pipeline (Figure 27). Spain and the USA have the highest installed capacity, but most plants were built under favourable remuneration schemes lasting a few years. New installations are at a standstill in these countries. On the contrary, China, Chile, and the MENA region are in the process of developing some new capacity. The size of these projects varies a lot, with the highest being 700 MWe for the DEWA project under construction in Dubai, which will also have the highest solar tower in the world (260m). However, most projects in the world are in the range of 10-200 MWe. Moreover, CSP projects have a long lifetime of 25-30 years. According to IRENA's database the capacity factor for CSP plants varies from 19% to 57% (ref. 5).

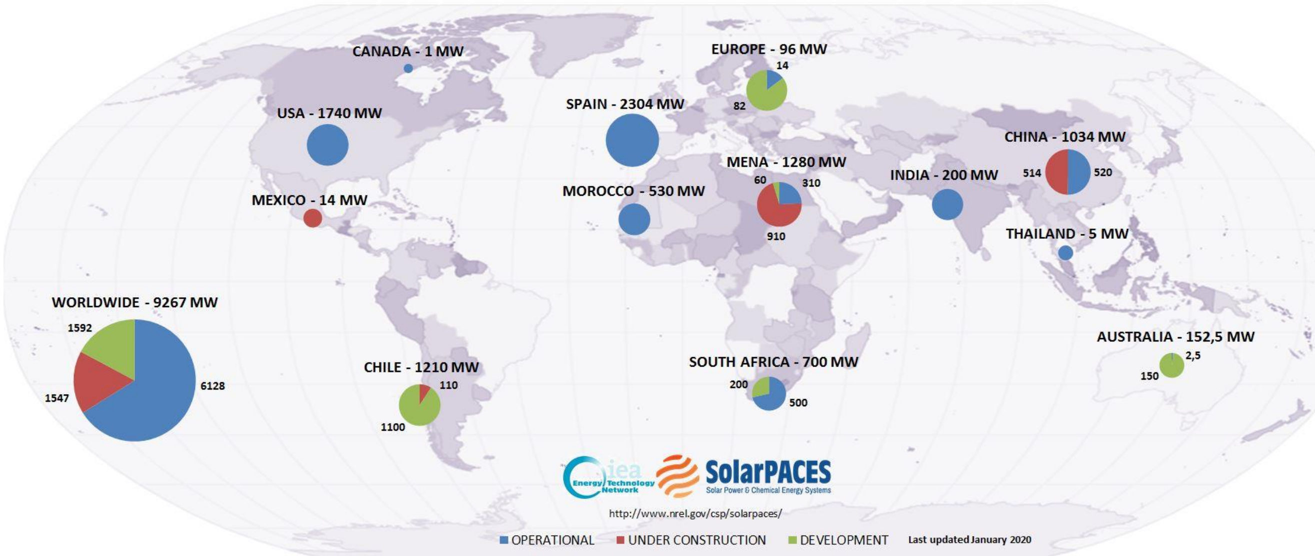


Figure 27: CSP Projects Around the World from SolarPACES database (ref. 11).

Advantages/disadvantages

Advantages:

- Renewable source of electricity.
- When installed with thermal storage, provides a high capacity factor and higher flexibility. This also overcomes the intermittency issue of solar technologies.
- Energy production is emission-free.
- Can be easily combined with solar PV or existing conventional thermal plants.

Disadvantages:

- More research and development are needed to be cost-competitive compared to solar PV and wind.
- Production is dependent on solar and weather conditions. Thermal storage needed to overcome this can increase initial investment costs.
- Cannot be deployed everywhere as it has specific DNI requirements.
- Large area requirements.
- Placement in remote areas can require grid expansion/reinforcements.

Environment

The production of electricity from a CSP has zero or negligible emissions. Even the emission associated with construction and installation are much lower than conventional fuel-based systems.

Employment

Based on Technical and Economic Data on All Operating Concentrating Solar Power Stations (ref 13) using the NREL, SolarPACES database and other sources, it is estimated that on average CSP plants can lead to over 600 jobs per year for construction of plants. As the O&M requirement is rather minimal for CSP plants, it leads to an annual operations and maintenance jobs creation of approximately 45 jobs on a yearly basis.

Another study based on experiences in Spain and USA suggests that number of jobs created by 2050 in the CSP sector can range between 70,000 in a conservative scenario and 1.4 million in a more advanced scenario (ref. 17)

Research and development

A 2020 analysis done by the IEA found that while solar PV is on track to meet IEA's Sustainable Development scenario 2040 targets, CSP is not (Figure 28). To meet the targets, the IEA estimates that CSP needs to produce 53.8 TWh by 2025 and 183.8 TWh by 2030. However, as of 2019 CSP is just at 15.6 TWh (ref. 10).

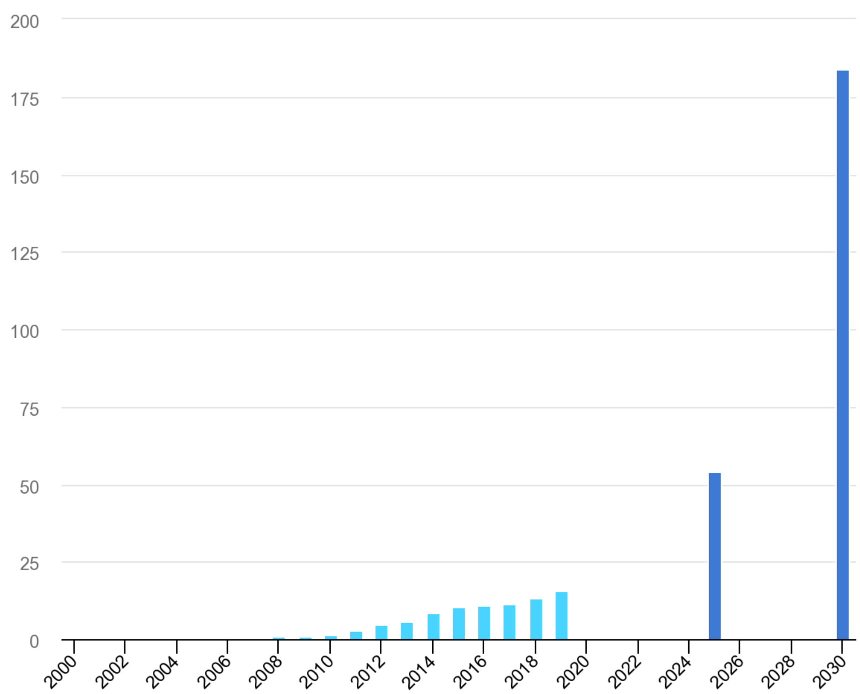


Figure 28: Concentrating solar power generation in the Sustainable Development Scenario, 2000-2030, IEA, Tracking Power 2020 (ref. 10).

For the CSP capacity to reach these levels, a significant amount of cost reduction is needed. Some of the areas that are being researched and that could lead to cost reductions are (ref. 17):

Solar Field:

- Collector with larger aperture (for parabolic trough)
- Improved optics through higher accuracy heliostats, improved field layout (for solar tower)
- Advanced assembly procedure, industrialized assembly, industrial automatization in manufacturing
- Higher reflectivity, higher cleanliness
- Improved durability
- Improved absorber coating
- Wireless power supply and control (heliostat)
- Improved optics through higher accuracy heliostats, improved field layout (tower)
- Improved O&M procedures

Thermal Storage:

- Higher temperature difference
- Adapted thermal storage materials
- Advanced charging and discharging, improved operation strategies in general

Power Block

- Higher cycle efficiency
- Improved hybridization concept
- Larger power block

System Efficiency

- Higher process temperature
- Lower parasitic consumption (higher temperature through larger aperture and other HTF; at the tower: gravitational pressure loss recovery)
- Adapted turbine design (for daily start-up)
- Improved control and O&M strategies/procedures

With respect to the power block a new advanced power cycle using supercritical CO_2 (sCO_2) has been under development and increasingly favoured for next generation CSP plants. It is essentially a modified closed Brayton cycle using the high-pressure and high density CO_2. sCO_2 cycles aim to utilise the relatively high density of supercritical CO_2 to reduce the pumping power requirement and hence improve the thermal efficiency over that of subcritical Brayton cycles. Supercritical CO_2 cycles offer several potential advantages, including (ref 8):

- High potential efficiency >50%
- Good match for temperatures of solar towers (up to around 850°C)
- Compactness, i.e., lower weight and volume (e.g. estimated diameter of a 3 MWe sCO_2 turbine is approx. 15 cm)
- Lower thermal mass
- Potentially lower installation and O&M costs due to simpler design and smaller size

Investment cost estimation

According to the IRENA cost database, 16 CSP plants were installed in 2018-2019 for which the installation costs varied between 3183 and 8645 $/kW with a weighted average of 5774 $/kW. Most of these projects included thermal storage. The LCOE of projects commissioned in this period ranged between 0.1 and 0.4 $/kWh with a weighted average of 0.182 $/kWh. Moreover, these values are expected to further decline in 2020 and 2021 with many projects to be commissioned in this period announcing PPA of less than 0.1 $/kWh (ref. 5).

For this catalogue the investment cost value for both, solar tower type and parabolic trough, are calculated using data from various international sources as summarised in **Error! Reference source not found.**. The estimate is under the assumption that future plants will always have thermal storage of 8-10 hours. One of the main differences that makes the cost of parabolic trough lower than solar tower type is the additional cost of the central tower. The value for 2020 is estimated based on the data from the various sources and then the learning rate based on capacity additions from IEA World Energy Outlook 2019 is applied.

Investment costs [$MUSD_{2019}$/MW]		2018/2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**5.4** (ST) **4.7** (PT)	**4.27** (ST) **3.71** (PT)	**2.97** (ST) **2.59** (PT)
International data	Internal Data (Ea)[1]		5.4 (ST) 4.7 (PT)		3.8 (ST) 3.3 (PT)
	NREL report	4.3 (ST) 4.3 (PT)			
	NREL ATB		6.8 (ST)		3.8 (ST)
	IRENA	5.7 (avg.) (3.7-8.6)			
Projection	Learning curve – cost trend [%]	-	100%	79%	55%

1 These values are based on internal data at Ea Energy Analyses for the GRIDSOL project in 2018-2019

Examples of current projects
There are no CSP projects in Ethiopia yet. But some international projects are described below.

DEWA's 700 MW Concentrated Solar Power project: The Noor Energy 1 CSP-PV solar power project is a 950 MW hybrid project (700MW CSP & 250MW PV). This is the fourth phase of the Mohammed Bin Rashid Al Maktoum Solar Park. It is the largest single-site concentrated solar power plant in the world using a combination of a 100MW central tower and three 200MW parabolic trough plants for a total of 700MW. This project has set the following eight world records in the CSP industry:

- World largest single-site investment project in CSP based on IPP model—USD 4.4 billion (AED 15.78 billion)
- World largest capacity of single CSP+PV project—950MW
- World largest area of single CSP+PV project—44 km^2
- World biggest quantity of molten salt used in single CSP project—550,000 tons
- World tallest CSP tower—260m
- World leading tower wireless heliostat technology—70,000 heliostats
- World largest trough in commercial CSP project— 8.2m
- Most competitive LCOE—USD 7.3 cents/kWh

Regarding the thermal storage, 15 hours for the central tower unit and 12.5 hours for each of the parabolic trough units are being considered.

The project is expected to be fully operational by the end of 2022. It is also estimated to have more than 1.6 million tons per year of carbon emissions savings, and power more than 320,000 residential units in Dubai. (ref 14)

Dadri ISCC Plant: India's state-owned utility NTPC's solar augmentation project is set to be Asia's first integrated solar thermal power plant at Dadri in Uttar Pradesh, India. The 15 MW_{th} CSP plant will be integrated into a wet-cooled 210 MW unit at the Dadri plant complex, which hosts 1.8 GW coal and 817 MW gas fired capacity. The plant is situated in Uttar Pradesh in north-west India and has a direct normal irradiance of 1169 kWh/m^2 per year. It is expected to supply 14 GWh per year and will be using Fresnel lens technology. The estimated project cost was 10.2 MUSD (2016). The capital cost requirements are much lower for CSP hybrid systems than stand-alone CSP electricity generation plants, due to lower equipment costs and the ability to integrate with existing power generation equipment (ref 15).

The table in Figure 29 provides a list of some CSP projects in China and other parts of the world with their investment cost as of September 2018.

#	Country	Project Name	Capacity (MW)	Technology Configuration	Total Investment ($M)	Total Investment per kW ($/kW)	TES Capacity (h)	Source
Power Tower								
1	China	Qinghai Delingha	50	MS Tower	$163	$3,260	6	(Shemer 2018b; Yang, Zhu, and Guo 2018)
2	China	Shouhang Dunhuang	100	MS Tower	$472	$4,720	11	
3	China	Qinghai Gonghe	50	MS Tower	$190	$3,800	6	
4	China	CPECC Hami	50	MS Tower	$245	$4,910	8	
5	China	Gansu Jinta	100	MS Tower	$388	$3,880	8	
6	China	Yumen Xinneng	50	Beam down	$278	$5,560	12	
7	China	Shangyi	50	MS Tower	$245	$4,890	6	(CSP Focus 2017c; Yang, Zhu, and Guo 2018)
8	Australia	Aurora	150	MS Tower	$650	$4,333	8	(Shemer 2018b; Lilliestam and Pitz-Paal 2018)
9	United Arab Emirates (UAE)	DEWA IV (tower portion)	100	MS Tower	$553 (tower portion)	$5,500 (for 700-MW site)	15	
10	Chile	Tamarugal	450	MS Tower	$2,700	$6,000	13	(Shemer 2018b)
11	Chile	Likana	390	MS Tower	$2,400	$6,154	13	
Parabolic Trough								
1	China	Royal Tech Yumen	50	Oil-Trough	$209	$4,180	9	(Shemer 2018b; Yang, Zhu, and Guo 2018; NREL and SolarPaces 2016)
2	China	Rayspower Yumen	50	Oil-Trough	Undisclosed	Unknown	9	
3	China	Urat	100	Oil-Trough	$435	$4,350	10	
4	China	CGN Delingha	50	Oil-Trough	$301	$6,020	9	
5	China	Gansu Gulang	100	Oil-Trough	Undisclosed	Unknown	7	
6	China	Gansu Akesai	50	MS Trough	$309	$6,170	15	
7	China	Zhangjiakou	64	MS Trough	$280	$4,370	16	
8	UAE	DEWA IV (Parabolic trough portion)	600	Oil-Trough	$3,317 (parabolic trough portion)	$5,500 (for 700-MW site)	11	(Shemer 2018b; Lilliestam and Pitz-Paal 2018)

Figure 29: List of some CSP projects in China and other parts of the world, including their investment cost (September 2018).

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18. Map obtained from Global Wind Atlas 3.0, https://globalwindatlas.info

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	CSP - Solar Tower with Thermal Storage								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)									
Generating capacity for total power plant (MWe)	100	150	200	50	200	50	400		1
Plant effieciency (annual solar to electricity), net (%)	18	18	20	17	20	17	20		3
Electricity efficiency (power block annual average), net (%)	38	40	42					A	2
Thermal storage efficiency, net (%)	95	95	95	90	99	90	99	B	1
Forced outage (%)	-	-							
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	30	35	40	25	40	25	40		3
Construction time (years)	2.0	2.0	1.5	1	3	1	3		3
Space requirement (1000 m^2/MWe)	0.040	0.040	0.040						4
Additional data for non thermal plants									
Capacity factor (%), theoretical	55	55	60	41	64	41	64	C	5
Capacity factor (%), incl. outages	55	55	60	41	64	41	64	C	5
Ramping configurations									
Ramping (% per minute)	9	9	9					E	10
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	5.40	4.27	2.97						5,6,7,8
- of which solar field (M$/MWt)	1.37	1.08	0.75						6,8
- of which thermal energy storage (M$/MWht)	0.29	0.23	0.16						6,8
- of which power block (M$/MWe)	1.04	0.88	0.78					D	8
- of which tower (M$/MWe)	0.70	0.55	0.39						6,8
Fixed O&M ($/MWe/year)	66,000	52,140	36,300						6,7
Variable O&M ($/MWh)	4.00	3	2						6,7

References:

1 O. Achkari, A. El Fadar, Latest developments on TES and CSP technologies – Energy and environmental issues, applications and research trends, Applied Thermal Engineering, Volume 167, 2020.

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8 Ea Energy Analyses, Internal data from GRIDSOL project and commercial developer.

9 Servert, et. al., Cost evolution of components and services in the STE sector: A two-factor learning curve, 2018

10 Technology Catalogue for Energy Storage (2020) by Medio Ambiente, INECC, Danish Energy Agency

Notes:

A Estimated based on development of steam turbines.

B Estimated round trip efficiency for molten salt thermal storage is 99%. Here a range is considered to account for potential losses during discharge.

C The capacity factor can vary significantly based on the size of thermal sorage.

D Learning rate not considered for the power block as it is a well established technology that is not expected to see a development as accelerated as other components.

E Note as per reference: Qualitative assessment by the authors is based on that consideration of Molten Salt storage shares characteristics with CAES to an extent in that a heat exchanger and turbine (driven by either hot air or steam) are applied. Therefore, expect similar response times.

Technology

Technology	CSP - Parabolic Trough with Thermal Storage								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)									
Generating capacity for total power plant (MWe)	100	150	200	10	200	10	400		1
Plant effieciency (annual solar to electricity), net (%)	14	14	16	13	16	13	16		3
Electricity efficiency (power block), net (%) annual average	38	40	42					A	2
Thermal storage efficiency, net (%)	95	95	95	90	99	90	99	B	1
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	30	35	40	25	40	25	40		3
Construction time (years)	2.0	2.0	1.5	1	3	1	3		3
Space requirement (1000 m^2/MWe)	0.040	0.040	0.040						4
Additional data for non thermal plants									
Capacity factor (%), theoretical	50	50	55	41	64	41	64	C	5
Capacity factor (%), incl. outages	50	50	55	41	64	41	64	C	5
Ramping configurations									
Ramping (% per minute)	9	9	9					E	10
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	4.70	3.71	2.59						5,6,7,8
- of which solar field (M$/MWt)	1.37	1.08	0.75						6,8
- of which thermal energy storage (M$/MWht)	0.29	0.23	0.16						6,8
- of which power block (M$/MWe)	1.04	0.88	0.78					D	8
Fixed O&M ($/MWe/year)	66,000	52,140	36,300						6,7
Variable O&M ($/MWh)	4.00	3	2						6,7

References:

1 O. Achkari, A. El Fadar, Latest developments on TES and CSP technologies – Energy and environmental issues, applications and research trends, Applied Thermal Engineering, Volume

2 ITP (2018), Concentrating Solar Thermal Technology Status – Informing a CSP Roadmap for Australia, IT P Thermal Pty Limited, Australia.

3 IEA-ETSAP and IRENA, Technology Policy Brief E10 - Concentrating Solar Power, 2013

4 NREL (2013), Sean Ong, Clinton Campbell, Paul Denholm, Robert Margolis, and Garvin Heath, Land-Use Requirements for Solar Power Plants in the United States.

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6 Ea Energy Analyses, Learning curve approach based on IEA WEO19

7 NREL, Turchi, Craig S., Matthew Boyd, Devon Kesseli, Parthiv Kurup, Mark Mehos, Ty Neises, Prashant Sharan, Michael Wagner, Timothy Wendelin. 2019. CSP Systems Analysis – Final Project Report.

8 Ea Energy Analyses, Internal data from GRIDSOL project and commercial developer.

9 Servert, et. al., Cost evolution of components and services in the STE sector: A two-factor learning curve, 2018

10 Technology Catalogue for Energy Storage (2020) by Medio Ambiente, INECC, Danish Energy Agency

Notes:

A Estimated based on development of steam turbines.

B Estimated round trip efficiency for molten salt thermal storage is 99%. Here a range is considered to account for potential losses during discharge.

C The capacity factor can vary significantly based on the size of thermal sorage.

D Learning rate not considered for the power block as it is a well established technology that is not expected to see a development as accelerated as other components.

E Note as per reference: Qualitative assessment by the authors is based on that consideration of Molten Salt storage shares characteristics with CAES to an extent in that a heat exchanger and turbine (driven by either hot air or steam) are applied. Therefore, expect similar response times.

5. GEOTHERMAL POWER PLANTS

Brief technology description

Based on their reservoir temperatures, Hochstein (1990) divided geothermal systems into three systems as per the following (ref. 1):

1. Low temperature geothermal systems which have reservoir temperature ranges less than 125°C (low enthalpy).
2. Medium temperature geothermal systems which have reservoir temperature ranges between 125°C and 225°C (medium enthalpy).
3. High temperature geothermal systems which have reservoir temperature ranges higher than 225°C (high enthalpy).

Geothermal to electrical power conversion systems typically in use in the world today may be divided into four energy conversion systems, which are:

- Direct steam plants; used at vapor-dominated reservoirs; dry saturated or slightly superheated steam with temperature range from 320°C down to around 200°C (Figure 30).
- Flashed steam plants; used at water-dominated reservoirs with temperatures higher than 182°C
  - Single flash plants; only high-pressure flash steam (Figure 30).
  - Double flash plants; low and high-pressure flash steam (Figure 31).
- Binary or twin-fluid system (based upon the Kalina or the Organic Rankin cycle); resource temperature range between 107°C and about 182°C (Figure 31).
- Hybrid; a combined system comprising two or more of the above basic types in series and/or in parallel (Figure 32).

Condensing and backpressure type geothermal turbines are essentially low-pressure machines designed for operation at a range of inlet pressures ranging from about 20 bar down to 2 bar, and saturated steam. A condensing type of system is the most common type of power conversion system in use today. They are generally manufactured in output module sizes of the following power ratings: 20 MW to 110 MW (the largest currently manufactured geothermal turbine unit is 117 MW). Binary type low/medium temperature units, such as the Kalina Cycle or Organic Rankin Cycle type, are typically manufactured in smaller modular sizes, i.e. ranging between 1 MW and 10 MW in size. Larger units specially tailored to a specific use are, however, available typically at a somewhat higher price.

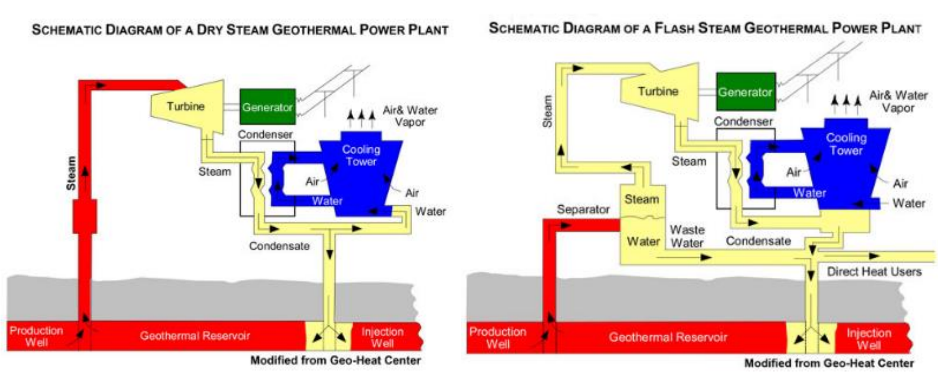

Figure 30: Direct and single flashed steam plants (ref. 7)

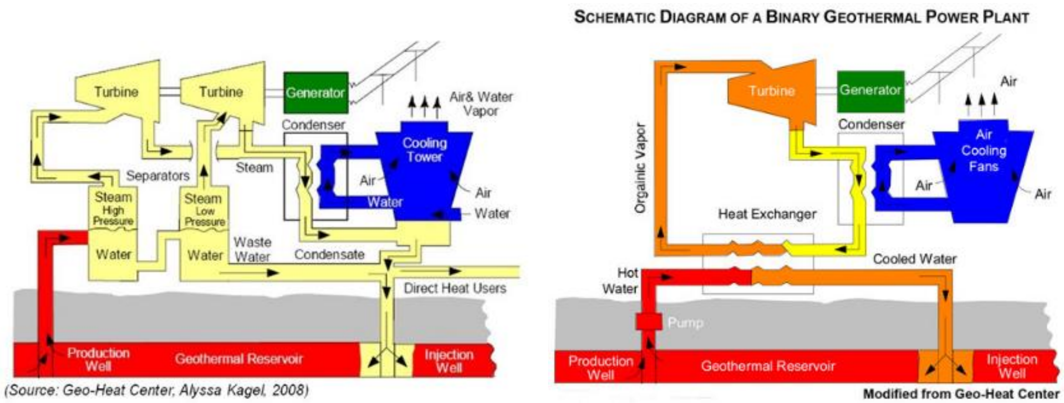

Figure 31: Double flashed and binary steam plants (ref. 7)

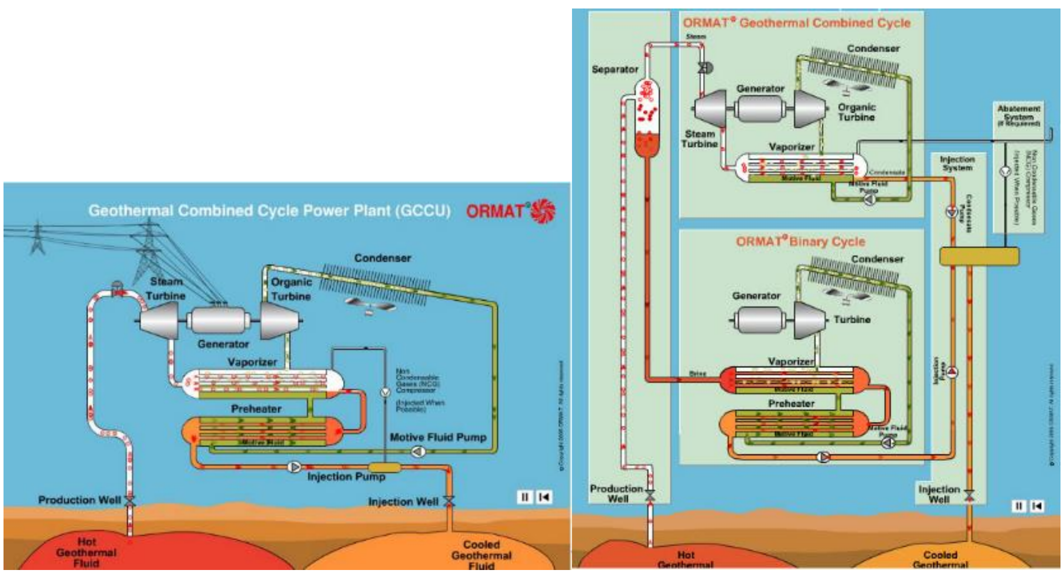

Figure 32: Hybrid/Combined Cycle plant (ref. 8)

The total capacity of geothermal power plants installed in 2019 in Ethiopia was 7.3 MW (ref. 16)

The geothermal potential in Ethiopia has been estimated to be 10 GW (Ministry of Water, Irrigation and Energy, 2019), hence there is a considerable opportunity for deploying geothermal power plants in the country. Currently, 25 high temperature areas are identified. Five of them are at the surface study program stage, while at 20 sites the detail surface exploration is completed. Out of these 20, drilling has been conducted in three areas and one area has a pilot plant. These 25 locations account for the estimated 10.8 GW geothermal potential. Locations are visible in Figure 33.

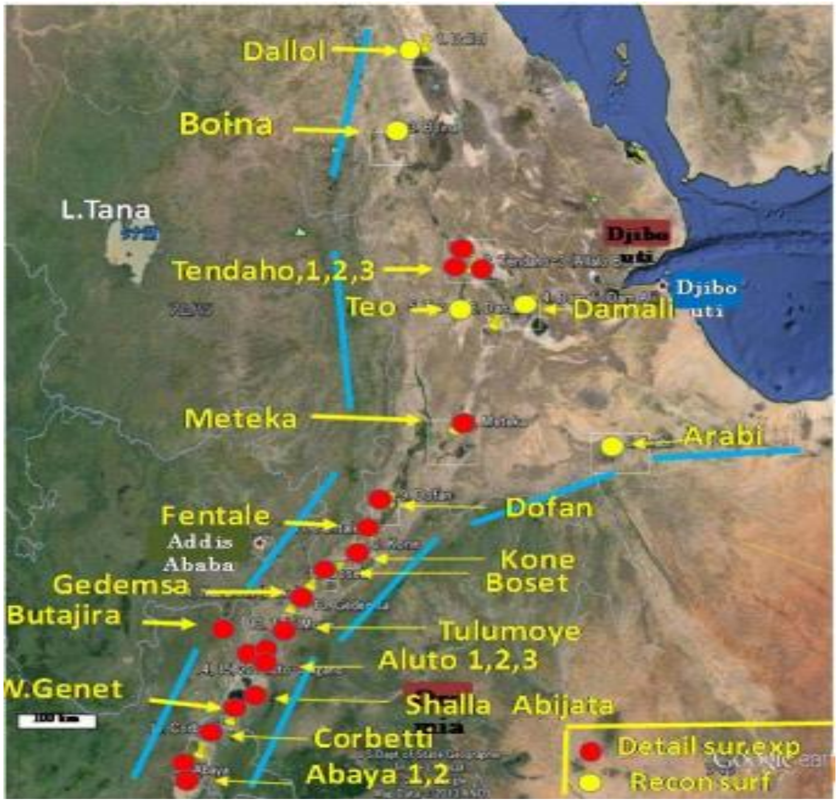

Figure 33: Geothermal resource areas in Ethiopia

Input
Heat from brine (saline water) from underground reservoirs.

Output
Electricity and heat.

Typical capacities
2.5-110 MW per unit.

Ramping configurations
Due to the high initial cost for geothermal plants, they should be used as base load to ensure an acceptable return on investment. For most geothermal power plants, flexibility is more of an economic issue than a technical one. In theory this flexibility can be used to increase economic feasibility

Advantages/disadvantages
Advantages:
- High degree of availability (>98% and 7500 operating hours/annum common).
- Small ecological footprints.
- Almost zero liquid pollution with re-injection of effluent liquid.
- Insignificant dependence on weather conditions.
- Comparatively low visual impact.

- Established technology for electricity production.
- Cheap running costs and "fuel" free.
- Renewable energy source and environmentally friendly technology with low CO_2 emission.
- High operation stability and long-life time.
- Potential for combination with heat storage.
- Geothermal is distinct from variable renewables, such as wind and solar, because it can provide a stable electricity output throughout the day and year.

Disadvantages:

- No security for success before the first well is drilled and the reservoir has been tested (ref. 11). Risky investment.
- High initial costs.
- The best reservoirs are not always located near cities.
- Need access to base load electricity demand.
- Drilling has an impact on the nearby environment.
- Risk of mudslides if not handled properly.
- The pipelines to transport the geothermal fluids will have an impact on the surrounding area.

Environment

Steam from geothermal fields contains Non-Condensable Gas (NCG) such as Carbon Dioxide (CO_2), Hydrogen Sulphide (H_2S), Ammonia (NH_3), Nitrogen (N_2), Methane (CH_4) and Hydrogen (H_2). Among them, CO_2 is the largest element within the NCG's discharged. CO_2 constitutes up to 95 to 98% of the total gases, H_2S constitutes only 2 to 3%, and the other gases are even less abundant.

H_2S is a colourless, flammable, and extremely hazardous gas. It causes a wide range of health effects, depending on concentration. Low concentrations of the gas irritate the eyes, nose, throat and respiratory system (e.g., burning/tearing of eyes, cough, shortness of breath). The safety threshold for hydrogen sulphide in humans can range from 0.0005 to 0.3 ppm.

Employment

According to a report in the USA, geothermal power plants employ about 1.17 persons per MW at each operating power plant. These are permanent jobs that last the entire 30 to 50-year lifetime of the power plant. In total, adding governmental, administrative, and technical related jobs, the geothermal industry employs about 2.13 persons per MW (ref. 15).

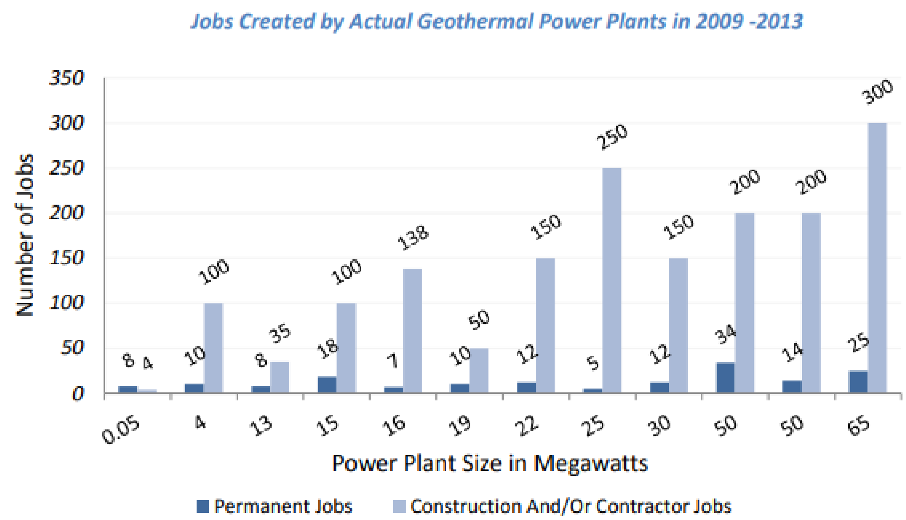

Figure 34: Jobs created by actual geothermal plants (ref. 15)

Research and development

Geothermal power plants are considered as a category 3 – i.e., commercial technologies, with potential of improvement.

Investment cost estimation

The investment costs of a geothermal project are heavily influenced by the exploration and drilling phases and by the type of geothermal power plant (flash or binary). Site selection and preparation are associated with a certain risk in the development of the geothermal project, thereby increasing the plant's cost of capital. Figure 35 illustrates the relationship between risk and cumulative costs in a geothermal project.

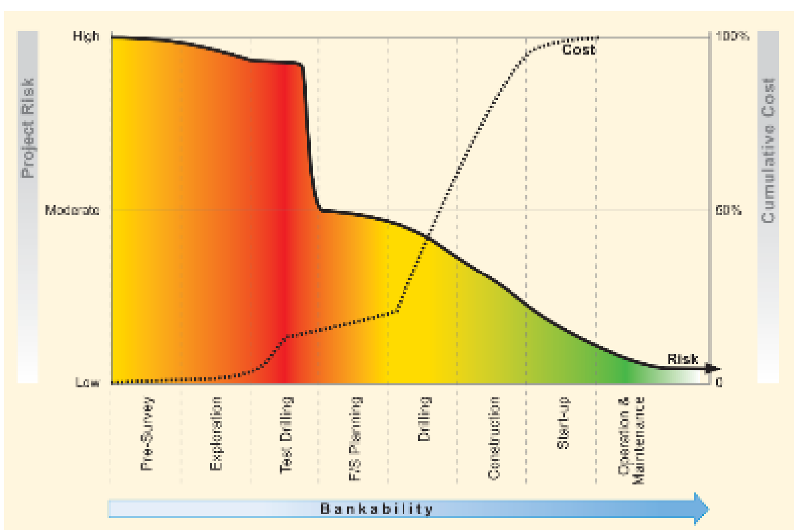

Figure 35: Qualitative risk and cumulative cost trends of a geothermal project (ref. 17).

Cost figures can therefore span over wide ranges. Flash plants are more economical because of an overall lower need for equipment, while the presence of an ORC (binary plants) increases project costs. The average cost gap due to the technological choice is quantified in 1 million USD/MW today. Cost data from relevant sources are reported in the table below, along with the recommended values for the investment costs.

Investment costs [$MUSD_{2019}$/MW]		2018	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**3.68** (flash) **5.77** (binary)	**3.16** (flash) **4.96** (binary)	**2.61** (flash) **4.10** (binary)
Ethiopian data	Estimated investment for planned local cases		3.42[1]		
International data	IRENA (various)	3.92		2.50	
	NREL ATB		4.40 (flash) 5.77 (binary)	3.83 (flash) 5.04 (binary)	3.47 (flash) 4.79 (binary)
	Lazard	4.6			
Projection	Learning curve – cost trend [%]	-	100%	86%	71%

[1] *Based on average estimated costs from feasibility and pre-feasibility studies for projects that are expected to be commission after 2023.*

While the average estimated investment cost for future projects is relatively lower, the final projections are empirically adjusted to account for the fact that these values are based on estimates for projects that are to be realised in the later part of this decade. The 2020 base value is considered a little higher accounting for the higher cost seen in existing projects, and the expected changes in future costs.

Examples of current projects

Ethiopia has a significant geothermal potential, especially along the Ethiopian Rift system. There currently exists one unique 7.3-MW geothermal power plant (Aluto Langano), which is in one of the richest geothermal areas of the country. The plant was commissioned in 1999. There are eight wells drilled to a maximum depth of 2500m (mid 1980-2014) out of which four are responsible for the 7.3 MW production. The maximum reservoir temperature encountered in the productive wells is about 350ºC. Currently it's under maintenance. However, a project is running to upgrade this facility to 70MW, with the support of the World Bank and Japan International Cooperation Agency, JICA. Surface exploration has been underway at Aluto. Further, the drilling of 22 wells is also in the early stages of equipment procurement. The first phase for a 35 MW power plant is under negotiation.

At Tendaho three sites have been identified for projects. Two of the sites are Alalobad and Ayrobera, where surface exploration is being conducted. Furthermore, the process for drilling of four wells at Alalobad, eight wells at Doubti and three slim holes at Ayrobera is in the pipeline. At Alalobad and Ayrobera drill sites are selected for testing. The World Bank project (Geothermal Sector Development Project (GSDP)) supports the Alalobad geothermal site development, the work at Ayrobera is being financed by JICA, and financing for the power plant at Doubti is under consideration from AFD.

Additionally, there are many private projects sites at Corbetti, Tulu moye, Ormat and RG Cluff (Table 8). The status of the different sites is as follows:

- Advance exploration stage: Tulu Moye and Corbetti

- Detailed investigation completed: Abaya
- Detailed investigation-Ongoing: Dofan, Fantale, Wondo gene, Duguna Fengo, Boku and Butajira
- Reconnaissance Stage: Kone, Meteka and Teo

Table 8: List of projects and their Investment Cost

No.	Project	Developer	Current status	Planned investment volume, mUSD[2]	Awarded grant volume, mUSD	(MWe)	Type
1	Aluto Langano expansion -Drilling Program	Public (EEP)	Drilling stage	109		70 (two stage development 35 MW at each stage)	Flash
2	Alalobad/Tedaho III -Drilling Program	Public (EEP)	Implementation	355	8.3	25	
3	Corbetti -Drilling Program	Private (Corbetti geothermal)	On process to move to drilling	994	8.0	150	Flash
4	Tulu moye -Surface Study -Drilling Program	Private (Tulu moye geothermal)	Test well drilling rig	638	1.3 10.1	150	Flash
5	Wodo Genet -Drilling Program	Private (Ormat Plc)	PPA negotiation	208.5	4.1	450	
6	Dofan -Drilling Program			370	3.4		
7	Daguna Fengo -Drilling Program			348	4.5		Binary[3]
8	Boku -Drilling Program			362	5.2		
9	Fentale -Surface Study -Drilling Program	Private (Cluff geothermal)	PPA negotiation	188	0.9 5.4	150	
10	Butajira -Surface study		PPA negotiation	1.1	0.6		
11	Abaya -Surface study	Private (geothermal)	Under discussion	2.6	1.4	300	
Total						**995**	

The Corbetti Caldera project in Oromia region, has a licensed area of 700 km^2. The project is expected to develop in four phases, where phase one includes two 5 MW wellhead generators and phases two, three and four will include one, four and five 50 MW steam turbines respectively. The initial two 5 MW turbines will be using a

[2] This includes Equipment, EPC costs etc.
[3] *According to ORMAT study*

conventional back pressure turbine solution, while a single flash steam turbine will be used for the 50MW units. The project is sponsored by Reykjavik Geothermal, Iceland drilling company, InfraCo Africa and Africa Renewable Energy Fund. The sponsorship commitment includes 140 mUSD (equity commitment up to phase 2).

Similarly, the project in Tulu Moye will cover 588 km². The four phases of the project will include one, two, two and five 50 MW single flash steam turbine units respectively. The 50 mUSD for development costs have been committed by the sponsors for the project Reykjavik Geothermal and Meridiam Infrastructure Africa Fund.

Additional remarks
The conversion efficiency of geothermal power developments is generally lower than that of conventional thermal power plants. The overall conversion efficiency is affected by many parameters including the power plant design (single or double flash, triple flash, dry steam, binary, or hybrid system), size, gas content, parasitic load, ambient conditions, and others. Figure 36 shows the conversion efficiencies for binary, single flash-dry steam, and double flash. The figure shows that double flash plants have higher conversion efficiency than single flash, but can have lower efficiency than binary plants for the low enthalpy range (750-850 kJ/kg). This has a direct impact on the specific capital of the plant as shown in Figure 37.

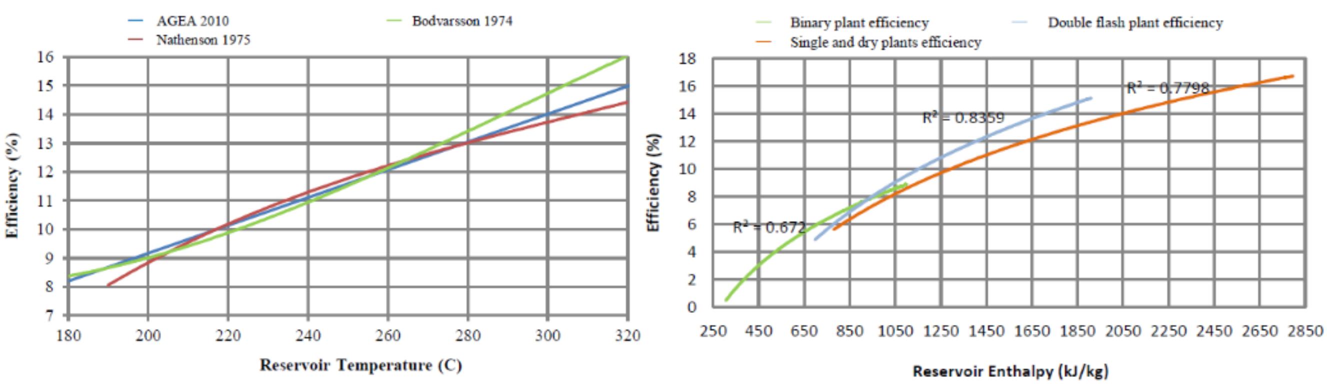

Figure 36: Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)

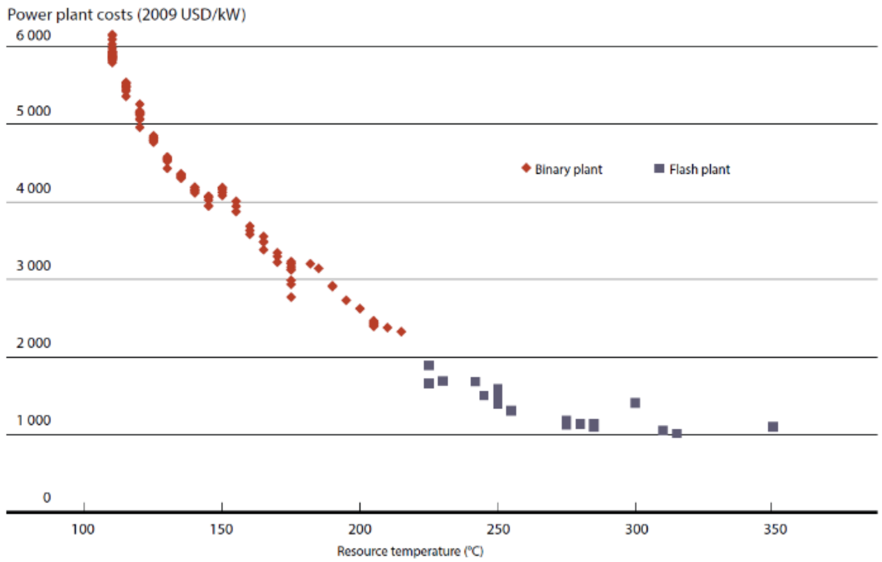

Figure 37: Indicative power plant only costs for geothermal projects by reservoir temperature (ref. 10). The power plant unit stands for around 40-50% of the total capital costs.

References

The following sources are used:

1. Hochstein, M.P., 1990. "Classification and assessment of geothermal resources" in: *Dickson MH and Fanelli M., Small geothermal resources*, UNITAEWNDP Centre for Small Energy Resources, Rome, Italy, 31-59.
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14. Geothermal Risk Mitigation Facility (GRMF) Overview of the Programme and Support to Geothermal Projects in Ethiopia

15. Geothermal Energy Association Issue Brief: Additional Economic Values of Geothermal Power, 2015
16. IRENA (2020) Renewable Energy Capacity Statistics
17. ESMAP (2012). Geothermal handbook: Planning and Financing Power Generation.

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Geothermal power plant - large system (flash or dry)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	50	50	50	30	500	30	500		1
Generating capacity for total power plant (MWe)	150	150	150	30	500	30	500		1
Electricity efficiency, net (%), name plate	16	17	18	8	18	10	20	A	5
Electricity efficiency, net (%), annual average	15	16	17	8	18	10	20	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1
Construction time (years)	2.0	2.0	2.0	1.5	3	1.5	3		1
Space requirement (1000 m^2/MWe)	30	30	30	20	40	20	40		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)	3	10	20						8
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	B	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	B	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	B	6
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-	B	6
N_2O (g per GJ fuel)	-	-	-	-	-	-	-	B	6
Financial data									
Nominal investment (M$/MWe)	3.68	3.16	2.61	3.00	5.75	1.70	4.55	D,E,F	1,2,3,4
- of which equipment	60%	60%	60%	40%	70%	40%	70%		3
- of which installation	40%	40%	40%	30%	50%	30%	50%		3
Fixed O&M ($/MWe/year)	50,000	43,000	35,500	37,500	62,500	26,600	44,400	D	1,4
Variable O&M ($/MWh)	0.25	0.22	0.18	0.19	0.31	0.14	0.23	D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7
Confirmation costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7

References:

1 PLN, 2017, data provided the System Planning Division at PLN
2 IEA, World Energy Outlook, 2015.
3 IRENA, 2015, Renewable Power Generation Costs in 2014.
4 Learning curve approach for the development of financial parameters.
5 Moon & Zarrouk, 2012, “Efficiency Of Geothermal Power Plants: A Worldwide Review”.
6 Yuniarto, et. al., 2015. “Geothermal Power Plant Emissions in Indonesia”.
7 Geothermal Energy Association, 2006, "A Handbook on the Externalities, Employment, and Economics of Geothermal Energy".
8 Geothermal Energy Association, 2015, "Geothermal Energy Association Issue Brief: Firm and Flexible Power Services Available from Geothermal Facilities"

Notes:

A The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in effciency will give a lower investment cost per MW. These large units are assumed to be flach units at high source temperatures.

B Geothermal do emit H_2S. From Minister of

C The learning rate is assumed to impact the

D Investment cost are including Exploration and Confirmation costs (see under Technology specific data).

E For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

Technology

Technology	Geothermal power plant - small system (binary or condensing)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	10	10	10	0.3	20	0.3	20		1,8
Generating capacity for total power plant (MWe)	20	20	20	5	30	5	30		1
Electricity efficiency, net (%), name plate	10	11	12	6	12	8	14	A	5
Electricity efficiency, net (%), annual average	10	11	12	6	12	8	14	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1
Construction time (years)	2.0	2.0	2.0	1,5	3	1,5	3		1
Space requirement (1000 m^2/MWe)	30	31	32	20	40	20	40		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	B	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	B	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	B	6
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-	B	6
N_2O (g per GJ fuel)	-	-	-	-	-	-	-	B	6
Financial data									
Nominal investment (M$/MWe)	5.77	4.96	4.10	4.3	7.2	1.70	4.55	C,D,E,F	1,2,4,8
- of which equipment	60%	60%	60%	40%	70%	40%	70%		3
- of which installation	40%	40%	40%	30%	50%	30%	50%		3
Fixed O&M ($/MWe/year)	65,000	55,900	46,200	48,800	81,300	34,700	57,800	C,D	1,4
Variable O&M ($/MWh)	0.37	0.32	0.26	0.28	0.46	0.20	0.33	C,D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7
Confirmation costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7

References:

1 PLN, 2017, data provided the System Planning Division at PLN
2 Budisulistyo & Krumdieck , 2014, "Thermodynamic and economic analysis for the pre- feasibility study of a binary geothermal power plant"
3 IRENA, 2015, Renewable Power Generation Costs in 2014.
4 Learning curve approach for the development of financial parameters.
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6 Yuniarto, et. al., 2015. “Geothermal Power Plant Emissions in Indonesia”.
7 Geothermal Energy Association, 2006, "A Handbook on the Externalities, Employment, and Economics of Geothermal Energy".
8 Climate Policy Initiative, 2015, Using Private Finance to Accelerate Geothermal Deployment: Sarulla Geothermal Power Plant, Indonesia.

Notes:

A The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in effciency will give a lower investment cost per MW. These smaller units are assumed to be binary units at medium source temperatures.

B Geothermal do emit H_2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm^3.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Investment cost are including Exploration and Confirmation costs (see under Technology specific data).

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

6. MUNICIPAL SOLID WASTE AND LANDFILL GAS POWER PLANTS

Brief technology description

Municipal solid waste (MSW) is a type of waste consisting of everyday items that are discarded by the public. The composition of MSW varies greatly from municipality to municipality, and it changes significantly with time. Treating MSW can occur via four different options: recycling, composting, disposal, and waste to energy. MSW can be used to generate energy. Several technologies have been developed that make the processing of MSW for energy generation cleaner and more economically feasible than ever before, including landfill gas capture, combustion, pyrolysis, gasification, and plasma arc gasification (ref. 1). While older waste incineration plants had a significant environmental impact, recent regulatory changes and new technologies have considerably reduced this issue. This chapter concentrates on incineration plants and landfill gas power plants.

Incineration power plants

The main components of waste to energy (WtE) incineration power plants are a waste reception area, a feeding system, a grate fired furnace interconnected with a steam boiler, a steam turbine, a generator, an extensive flue gas cleaning system and systems for handling the combustion and flue gas treatment residues (Figure 38).

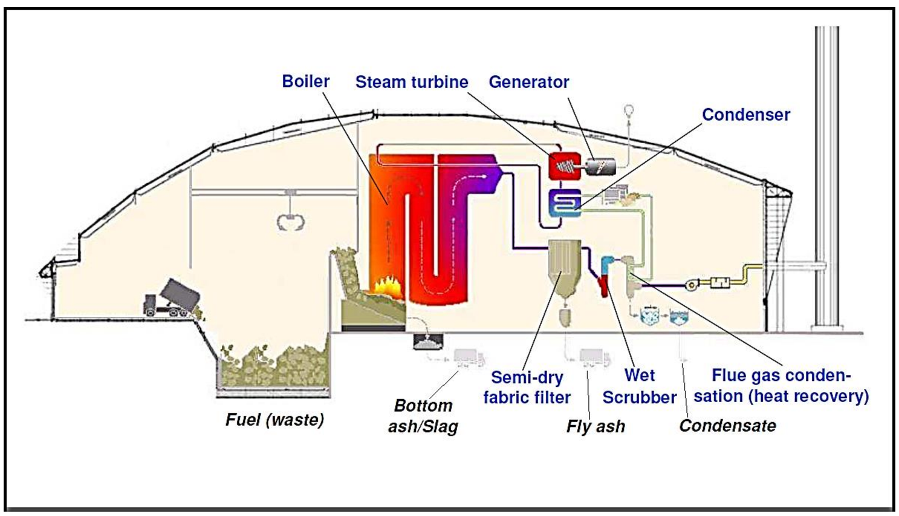

Figure 38: Typical Waste to Energy Plant (Nordic Heat of Sweden, 2017)

The method of using incineration to convert municipal solid waste to energy is a relatively old method of WtE production. Incineration generally entails burning waste (residual MSW, commercial, industrial, and refuse-derived fuel) to boil water which powers steam generators that make electric energy and heat to be used in homes, businesses, institutions, and industries. One problem associated with incinerating MSW to make electrical energy is the potential for pollutants to enter the atmosphere with the flue gases from the boiler. These pollutants can be acidic and were reported to cause environmental damage in the 1980s by turning rain into acid rain. Since then, the problem was solved using lime scrubbers and electro-static precipitators on smokestacks. By passing the smoke through the basic lime scrubbers, any acids that might be in the smoke are neutralized, which prevents the acid from reaching the atmosphere and damanging the environment. Many other devices, such as fabric filters, reactors, and catalysts are employed to destroy or capture other regulated pollutants.

The caloric value of MSW depends on the composition of the waste. Table 9 gives the estimated caloric value of MSW components on dry-weight basis.

Table 9: Average heat values of MSW components (ref. 2)

Component	**Heating Value (GJ/ton)**
Food Waste	4.7
Paper	16.8
Cardboard	16.3
Plastics	32.6
Textiles	17.5
Rubber	23.3
Leather	1.7
Garden trimmings	6.5
Wood	18.6
Glass	0.1
Metals	0.7

The waste is delivered by trucks and is normally incinerated in the state in which it arrives. Only bulky items are shredded before being fed into the waste bunker.

The potential to utilise waste in WtE plants is influenced by the density of the waste, its moisture and ash content, its heating value and particle size distribution. Thermal WtE technology feedstock is dependent on its chemical content (carbon, hydrogen, oxygen, nitrogen, sulphur and phosphorous) and its volatile content. Typically, waste with a calorific value greater than 1,400 kcal/kg is suitable for thermal WtE feedstock.

Landfill gas power plants

The disposal of waste by land filling or land spreading is the current most common fate of solid waste. As solid waste in landfills decomposes, landfill gas is released. Landfill gas consists of approximately 50% methane, 42% carbon dioxide, 7% nitrogen and 1% oxygen compounds. Landfill gas is a readily available, local, and renewable energy source that offsets the need for non-renewable resources such as oil, coal and gas.

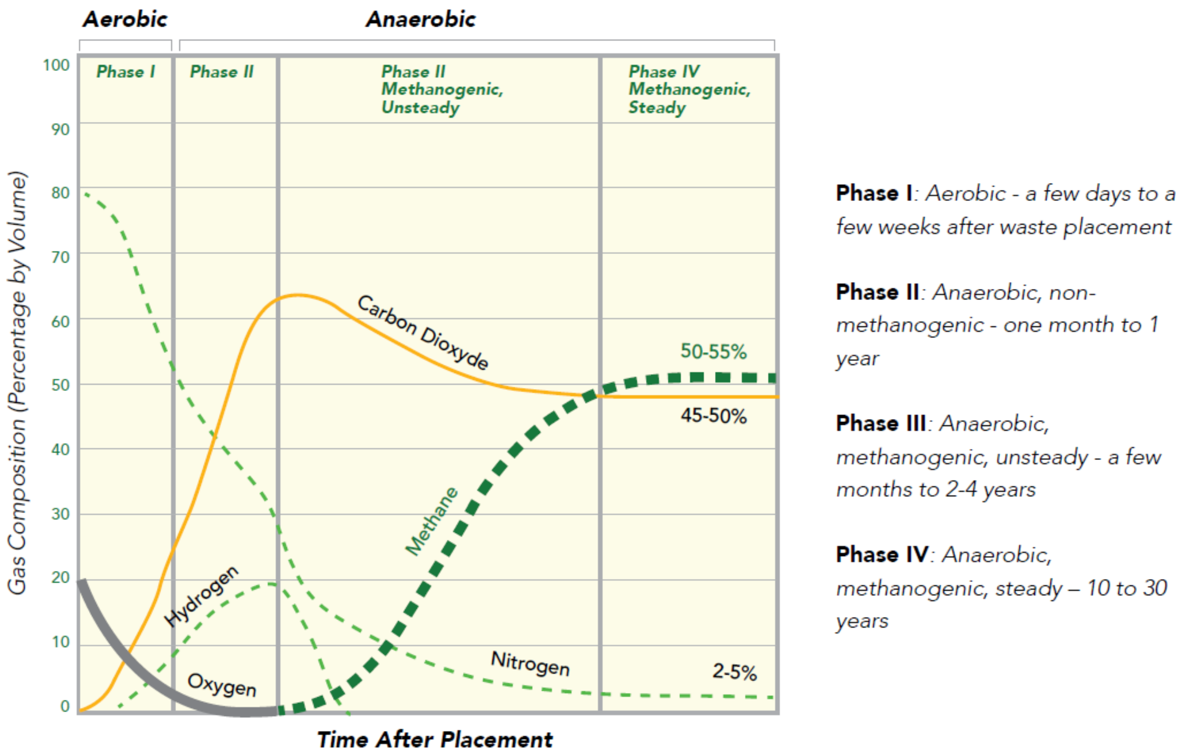

Figure 39: LFG generation and changes over time (ref. 13).

Using gas engines, landfill gas can be used as fuel feedstock to produce electricity. The production volume of landfill gas from the same sites can have a range of 2-16 m^3/day.

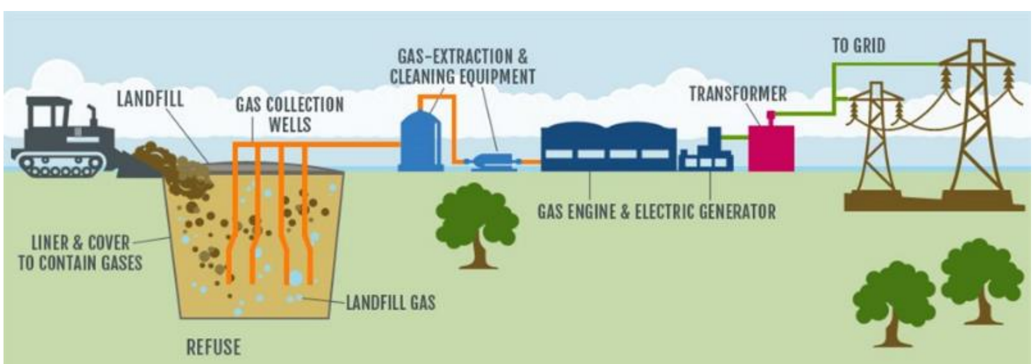

Figure 40: Landfill gas to energy (ref. 5)

The table in Figure 41 summarizes the suitability of each technology to selected waste streams from Municipal, Agricultural, and Industrial sources. The basic outputs of each technology are also given in terms of electricity, heat, biogas, digestate, syngas and other commercial solids.

CONVERSION TECHNOLOGIES		Anaerobic digestion	Landfill gas recovery	Incineration	Gasification	Pyrolysis
WASTE STREAMS						
Municipal or industrial	Food waste	🟢	🟢	🟡	🟡	🟡
	Garden and park waste	🟢	🟢	🟡	🔴	🔴
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Refuse Derived Fuel	🔴	🔴	🟢	🟢	🟢
	Inert	🔴	🟢	🔴	🔴	🔴
	Hazardous	🔴	🔴	🟡	🔴	🔴
	Solid Recovered Fuel	🔴	🔴	🟢	🟢	🟢
Agricultural	Biomass	🟢	🟢	🟡	🟡	🟡
	Animal waste	🟢	🟢	🟡	🟡	🟡
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Hazardous	🔴	🔴	🟡	🔴	🔴
OUTPUTS						
Electricity		x	x	x	x	x
Heat		x	x	x	x	x
Biogas		x	x			
Digestate		x				
Syngas					x	x
Other commercial solids				x	x	x

Key: 🟢 Directly suitable 🟡 Likely to require pre-treatment 🔴 Unsuitable

Figure 41: Summary of waste to energy technologies' suitability per waste stream and potential output (ref. 4)

Input

MSW and other combustible waste, water and chemicals for flue gas treatment, gasoil or natural gas for auxiliary burners (if installed), and in some cases biomass or fuel oil for starting and closing down.

Landfill gas is the fuel feedstock for the landfill gas power plants.

Output

For combustion systems, the outputs are electricity and if relevant also heat as hot water (cogeneration plants), bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the SO_2-step, when gypsum is not produced).

For landfill gas systems, the outputs are electricity and heat. The landfill gas which has been cleaned (from sulphur and carbon dioxide contents) can be sold as commercial gas through natural gas pipeline networks.

Typical capacities

Medium: 10 – 50 MW.
Small: 1 – 10 MW.

Ramping configurations

The plants that using combustion technologies can be down regulated to about 50% of the nominal capacity, under which limit the boiler may not be capable of providing adequate steam quality and environmental performance. For emission control reasons and due to high initial investments, they should be operated as base load. In extraction cogeneration plants, it is possible to regulate the power output also by adjusting the electricity-to-heat ratio.

Landfill gas to energy plants can also be ramped up or down depending on the availability of the landfill gas in a storage.

Advantages/disadvantages

Advantages:

- Waste volumes are reduced by an estimated 80-95%.
- Reduction of other electricity generation.
- Reduction of waste going to landfills.
- Avoidance of disposal costs and landfill taxes.
- Use of by-products as fertilizers.
- Avoid or utilisation of methane emissions from landfills.
- Reduction in carbon emitted.
- Domestic production of energy.
- The ash produced can be used by the construction industry.
- Incineration also eliminates the problem of leachate that is produced by landfills.
- Better control over noise and odours.
- Elimination of harmful germs and chemicals.
- Operation does not depend on weather.
- Contributes to recycling of metal.
- Requires not so much space.

Disadvantages:

- Incineration facilities are expensive to build, operate, and maintain. Therefore, incineration plants are usually built for environmental benefits before power generation reasons.
- Smoke and ash emitted by the chimneys of incinerators include acid gases, nitrogen oxide, heavy metals, particulates, and dioxin, which is a carcinogen. Even with controls in place, some remaining dioxin still enters the atmosphere.
- Incineration ultimately encourages more waste production because incinerators require large volumes of waste to keep the fires burning, and local authorities may opt for incineration over recycling and waste reduction programs.
- May contribute to environmental injustice when poorer communities are disproportionally exposed to pollution.

In developing countries like Ethiopia, waste incineration is likely not as practical as in developed countries, since a high proportion of waste in developing countries is composed of kitchen scraps. Such organic waste is composed of higher moisture content (40-70%) than waste in industrialized countries (20-40%), making it more difficult to burn.

Environment
Municipal solid waste (MSW) incinerators require effective flue gas treatment (FGT) to meet stringent environmental regulations. However, this in turn generates additional environmental costs through the impacts of materials and energy used in the treatment. A total of eight technologies: electro-static precipitators and fabric filters for removal of particulate matter; dry, semi-dry and wet scrubbers for acid gases; selective non-catalytic and catalytic reduction of nitrogen oxides (NOx); and activated carbon for removal of dioxins and heavy metals are now commercially available on the market (ref. 11).

The incineration process produces two types of ash. Bottom ash comes from the furnace and is mixed with slag, while fly ash comes from the stack and contains components that are more hazardous. In municipal waste incinerators, bottom ash is approximately 10% by volume and approximately 20 to 35% by weight of the solid waste input. Fly ash quantities are much lower, generally only a few percent of input. Emissions from incinerators can include heavy metals, dioxins, and furans, which may be present in the waste gases, water or ash. Plastic and rubber are the major source of the calorific value of the waste. The combustion of plastics, like polyvinyl chloride (PVC) gives rise to these highly toxic pollutants.

Leachate generation is a major problem for municipal solid waste (MSW) landfills and causes significant threats to surface water and groundwater. Leachate may also contain heavy metals and high ammonia concentration that may be inhibitory to the biological processes. Technologies for landfill leachate treatment include biological treatment, physical/chemical treatment, and emerging technologies such as reverse osmosis (RO) and evaporation.

Employment
According to IRENA, municipal and industrial waste accounted for 39.000 jobs in 2019. This makes the sector one of the renewable technologies with fewest employments (ref. 12).

Research and development
Waste incineration plants is a very mature technology (category 4), whereas landfill gas is commercialised, but still being gradually improved (category 3). There are, however, several other new and emerging technologies that can produce energy from waste and other fuels without direct combustion. Many of these technologies have the potential to produce more electric power from the same amount of fuel than would be possible by direct combustion. This is mainly due to the separation of corrosive components (ash) from the converted fuel, thereby allowing higher combustion temperatures in e.g., boilers, gas turbines, internal combustion engines, fuel cells. Some can efficiently convert the energy into liquid or gaseous fuels:

- *Pyrolysis* — MSW is heated in the absence of oxygen at temperatures ranging from 290 to 700 °C. This releases a gaseous mixture called syngas and a liquid output, both of which can be used for electricity, heat, or fuel production. The process also creates a relatively small amount of charcoal (ref. 1).
- *Gasification* — MSW is heated in a chamber with a small amount of oxygen present at temperatures ranging from 400 to 1,650 °C. This creates syngas, which can be burned for heat or power generation, upgraded for use in a gas turbine, or used as a chemical feedstock suitable for conversion into renewable fuels or other bio-based products (ref. 1).
- *Plasma Arc Gasification* — Superheated plasma technology is used to gasify MSW at temperatures of 5,500 °C or higher - an environment comparable to the surface of the sun. The resulting process

incinerates nearly all the solid waste while producing from two to ten times more energy compared to conventional combustion (ref. 1).

Table 10: Efficiency of Energy Conversion Technologies (ref. 9 and ref. 10)

Technology	Efficiency (kWh/ton of waste)
Landfill gas	41 – 84
Combustion (Incinerator)	470 – 930
Pyrolysis	450 – 530
Gasification	400 – 650

Table 11: Expected Landfill Diversion (ref. 11 and ref. 12)

Technology	Land diversion (% weight)
Landfill gas	0
Combustion (Incinerator)	75*
Pyrolysis	72 – 95
Gasification	94 – 100

* 90% by volume

Investment cost estimation

The Reppie waste to energy plant in Addis Ababa is the only local case so far that provides a local context for investment cost estimation. However, considering this as a special case and the fact that international prices seen so far are relatively higher, the final estimate here gives a little more weightage to the international data. In the international data, the costs tend to be higher due to the requirement for pollution control which can be expensive. Also, steam data and therefore power efficiency is higher, but this also comes with higher costs for the construction of the plant. Assuming that Ethiopia will also take up such practices moving forward, the final estimate considers the one local case as a special project, and future projects may be more in line with international estimates.

Investment costs [$MUSD_{2019}$/MW]		2019	2020	2030	2050
Catalogues	**Technology Catalogue for Ethiopia (2021)**		5.6	5.3	4.6
Ethiopian cases	Reppie WtE plant	2.43			
International data	Danish technology catalogue	-	7.1	6.7	5.9

Examples of current projects

Reppie waste to energy plant, located at the site of the main landfill (Koshe) of the capital Addis Ababa, is the first waste to energy power plant of Ethiopia. It is expected to receive 1,400 tonnes of municipal waste a day, representing an annual waste disposal capacity of 420,000 tonnes, and will be a vital waste disposal and renewable-electricity generation facility for the city of Addis Ababa. It will help the City dispose close to three quarters of its daily waste generation in an efficient and environmentally friendly manner, whilst at the same time producing an expected electricity production capacity of 185 GWh per year. The facility has a thermal capacity of 110 MWth. The plant has two linesand a 25 MWe condensing turbine generator. There are two sets of 25 MWe turbines for redundant operation, which will ensure increased plant availability and reliability The total investment cost for the plant is 120 MUSD.

The plant process is unsorted municipal solid waste is delivered to the waste reception hall by the Municipality's trucks. Two semi-automatic grab cranes mix the waste before it is loaded onto the 2 x separate lines where the waste is combusted. The plant is designed to accept a calorific value range of 5.5 – 9.5 MJ/kg of waste. Over 80% of this waste is eliminated and what remains is converted into ash. The bottom ash is to be sold as a building material to the local construction industry or safely used as landfill cover in the new Sendafa Landfill site. The Facility uses magnets to recover steel and other ferrous metals for additional recycling. The Facility's energy-recovery comes from the generation of superheated steam to drive a 25 MWe steam generator and produces an expected 185 GWh of electricity every year (ref. 10).

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The following sources are used:

1. Glover and Mattingly, 2009. "Reconsidering Municipal Solid Waste as a Renewable Energy Feedstock", *Issue Brief*, Environmental and Energy Study Institute (ESSI), Washington, USA.
2. Reinhart, 2004. Estimation of Energy Content of Municipal Solid Waste, University of Central Florida, USA.
3. Viva Media Baru. http://www.viva.co.id. Accessed: 1st August 2017.
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9. Texas Comptroller of Public Accounts, 2008. "The Energy Report 2008: Chapter 18 Municipal Solid Waste Combustion." Texas Comptroller of Public Accounts.
10. Reppie Waste-to-Energy Facility Brochure (received from EEP)
11. Jun Dong, Harish Kumar Jeswani, Ange Nzihou, Adisa Azapagic, The environmental cost of recovering energy from municipal solid waste, Applied Energy Volume 267, 1 June 2020.
12. IRENA. 2020. Renewable energy and Jobs – annual review 2020.
13. MEMR. (2015). Waste to energy guidebook.

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Incineration Power Plant - Municipal Solid Waste								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	25	25	25						
Generating capacity for total power plant (MWe)	50	50	50						
Electricity efficiency, net (%), name plate	29%	30%	31%	28%	32%	30%	33%	A	1
Electricity efficiency, net (%), annual average	28%	29%	29%	26%	30%	28%	31%		1
Forced outage (%)	1%	1%	1%						1
Planned outage (weeks per year)	2,9	2,6	2,1						1
Technical lifetime (years)	25	25	25						1
Construction time (years)	2,5	2,5	2,5						1
Space requirement (1000 m^2/MWe)	1,5	1,5	1,5						1
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10	7,5	12,5	7,5	12,5	C	1
Minimum load (% of full load)	20	20	20	15,0	25,0	15,0	25,0	C	1
Warm start-up time (hours)	0,5	0,5	0,5	0,4	0,6	0,4	0,6	C	1
Cold start-up time (hours)	2	2	2	1,5	2,5	1,5	2,5	C	1
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	5,6	5,3	4,6	4,2	5,8	3,5	5,8	C	1,2
- of which equipment	3,3	2,9	2,3	2,5	2,9	1,7	2,9		1
- of which installation	2,3	2,4	2,3	1,7	2,9	1,7	2,9		1
Fixed O&M ($/MWe/year)	170.564	157.891	134.654	136.500	213.200	107.700	168.300	C	1
Variable O&M ($/MWh)	23,0	22,0	21,0	17,3	26,3	15,8	26,3	C	1
Start-up costs ($/MWe/start-up)									
Technology specific data									
Waste treatment capacity (tonnes/h)	74,7	74,7	74,7					B	

References:

1 Danish Technology Catalogue "Technology Data for Energy Plants, Danish Energy Agency 2020

2 Reppie Waste-to-Energy Facility Brochure (received from EEP)

Notes:

A Based on experience from the Netherlands where 30 % electric efficiency is achieve. 1 %-point efficiency subtracted to take into account higher temperature of cooling water in Ethiopia (approx. +20 C).

B The investment cost is based on waste to energy CHP plant in Denmark, according to Ref 1. A waste treatment capacity of 27,7 tonnes/h is assumed and an energy content of 10,4 GJ/ton. The specific finalcial data is adjusted to reflect that the plant in Indonesia runs in condensing mode and hence the electric capacity (MWe) is higher than for a combined heat and power backpressure plant with the same treatment capacity.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Calculated from size, fuel efficiency and an average calory value for waste of 9.7 GJ/ton.

Technology

Technology	Landfill Gas Power Plant - Municipal Solid Waste								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1	0.5	10	0.5	10		1
Generating capacity for total power plant (MWe)	1	1	1	0.5	10	0.5	10		1
Electricity efficiency, net (%), name plate	35	35	35	25	37	25	37		2
Electricity efficiency, net (%), annual average	34	34	34	25	37	25	37		2
Forced outage (%)	5	5	5	2	15	2	15		4
Planned outage (weeks per year)	5	5	5	2	15	2	15		4
Technical lifetime (years)	25	25	25	20	30	20	30		3
Construction time (years)	1.5	1.5	1.5	1	3	1	3		3
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.5	2.5	2.5	2.3	2.8	2.3	2.9	A	3
- of which equipment	0.7	0.7	0.7	0.7	0.8	0.7	0.8		5
- of which installation	0.3	0.3	0.3	0.3	0.3	0.3	0.3		5
Fixed O&M ($/MWe/year)	125,000	125,000	125,000	113,640	137,500	113,636	143,750	A	3
Variable O&M ($/MWh)	13.5	13.5	13.5	10.1	16.9	10.1	16.9		
Start-up costs ($/MWe/start-up)									
Technology specific data									

References:

1 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority, Jakarta, Indonesia

2 Renewables Academy" (RENAC) AG, 2014, "Biogas Technology and Biomass", Berlin, Germany.

3 IEA-ETSAP and IRENA, 2015. "Biomass for Heat and Power, Technology Brief".

4 PLN, 2017, data provided the System Planning Division at PLN

5 MEMR, 2015, "Waste to Energy Guidebook", Jakarta, Indonesia.

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 10-15%.

7. GAS CYCLES

Brief technology description
There are two main types of gas cycle processes, the simple-cycle and combined cycle. These are further explained below.

Simple cycle
The main components of a simple-cycle (or open cycle) gas turbine power unit are a gas turbine, a gear (when needed) and a generator (Figure 42).

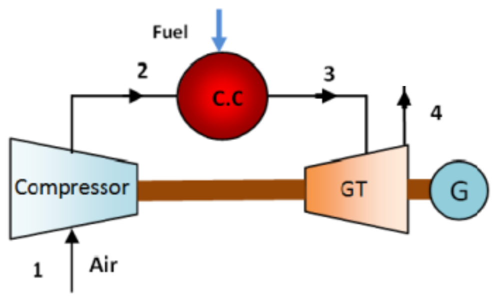

Figure 42: Process diagram of a SCGT (ref. 1)

There are in general two types of gas turbines:
1. Industrial turbines (also called heavy-duty) and
2. Aero-derivative turbine.

Industrial gas turbines differ from aero-derivative turbines in the way that the frames, bearings, and blading are of heavier construction. Additionally, industrial gas turbines have longer intervals between services compared to the aero-derivatives.

Aero-derivative turbines benefit from higher efficiency than industrial ones and the most service-demanding module of the aero-derivative gas turbine can normally be replaced in a couple of days, thus keeping a high availability.

Gas turbines can be equipped with compressor intercoolers where the compressed air is cooled to reduce the power needed for compression. The use of integrated recuperators (preheating of the combustion air) to increase efficiency can also be made by using air/air heat exchangers - at the expense of an increased exhaust pressure loss. Gas turbine plants can have direct steam injection in the burner to increase power output through expansion in the turbine section (Cheng Cycle).

Small (radial) gas turbines below 100 kW are now on the market, the so called micro-turbines. These are often equipped with preheating of combustion air based on heat from gas turbine exhaust (integrated recuperator) to achieve reasonable electrical efficiency (25-30%).

Combined cycle

Main components of combined-cycle gas turbine (CCGT) plants include: a gas turbine, a steam turbine, a gear (if needed), a generator, and a heat recovery steam generator (HRSG)/flue gas heat exchanger, as visible in Figure 43.

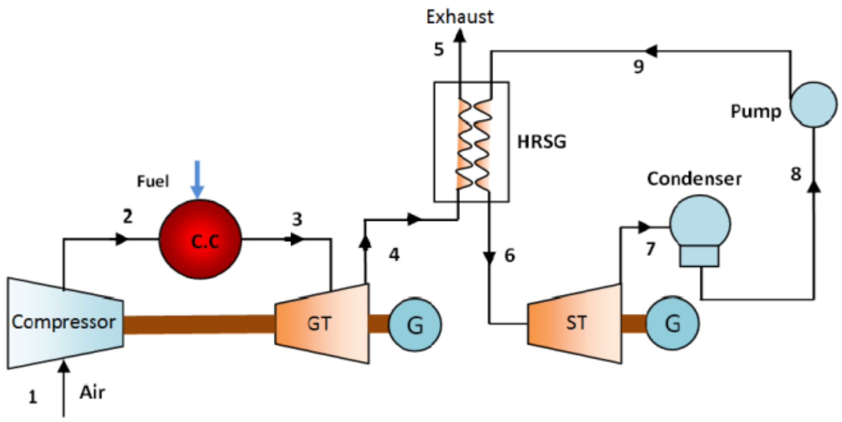

Figure 43: Process diagram of a CCGT (ref. 1)

The gas turbine and the steam turbine might drive separate generators (as shown) or drive a shared generator. Where the single-shaft configuration (shared) contributes with higher reliability, the multi-shaft (separate) has a slightly better overall performance. The condenser is cooled by sea water or water circulating in a cooling tower.

The electric efficiency depends, besides the technical characteristics and the ambient conditions, on the flue gas temperature and the temperature of the cooling water. The power generated by the gas turbine is typically two to three times the power generated by the steam turbine.

Input

Typical fuels are natural gas (including LNG) and light oil. Some gas turbines can be fuelled with other fuels, such as LPG, biogas etc., and some gas turbines are available in dual-fuel versions (gas/oil).

Gas fired turbines need an input pressure of the fuel (gas) of 20-60 bar, dependent on the gas turbine compression ratio, i.e., the entry pressure in the combustion chamber.

Typically, aero-derivative gas turbines need higher fuel (gas) pressure than industrial types.

Typical capacities

Simple-cycle gas turbines are available in the 30 kW – 450 MW range. Most CCGT units have an electric power rating of >40 MW.

Ramping configurations

A simple-cycle gas turbine can be started and stopped within minutes, supplying power during peak demand. Because they are less power efficient but cheaper in capital costs than combined cycle plants, they are in most places used as peak or reserve power plants, which operate anywhere from several hours per day to a few dozen hours per year.

However, every start/stop has a measurable influence on service costs and maintenance intervals. As a rule-of-thumb, a start costs 10 hours in technical life expectancy.

Gas turbines can operate at part load. This reduces the electrical efficiency and at lower loads the emission of e.g., NO_x and CO will increase, also per Nm^3 of gas consumed. The increase in NO_x emissions with decreasing load places a regulatory limitation on the ramping ability. This can be solved in part by adding de- NO_x units.

CCGT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NO_x emission.

If the steam turbine is not running, the gas turbine can still be operated by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack.

The larger gas turbines for CCGT installations are usually equipped with variable inlet guide vanes, which will improve the part load efficiencies in the 85-100% load range, thus making the part load efficiencies comparable with conventional steam power plants in this load range. Another means to improve part load efficiencies is to split the total generation capacity into several CCGTs. However, this will generally lead to a lower full load efficiency compared to one larger unit.

Advantages/disadvantages

Advantages:

- Simple-cycle gas turbine plants have short start-up/shut down time, if needed. For normal operation, a hot start will take some 10-15 minutes.
- Large combined-cycle units have the highest electricity production efficiency among fuel-based power production.
- CCGTs are characterized by low capital costs, high electricity efficiencies, short construction times and short start-up times. The economies of scale are however substantial, i.e. the specific cost of plants below 200 MW increases as capacity decreases.
- Low CO_2 emissions as compared to other fossil-based technologies.
- Requires smaller amounts of water than a conventional steam power plant.
- Relatively less auxiliaries than steam turbine
- Low capital cost
- Require little cooling system
- No vacuum required at any place.
- Simple speed control (only air, fuel, RPM)

Disadvantages:

- Concerning larger units above 15 MW, the combined cycle technology has so far been more attractive than simple-cycle gas turbines, when applied in cogeneration plants for district heating. Steam from other sources (e.g., waste fired boilers) can be led to the steam turbine part as well. Hence, the lack of a steam turbine can be considered a disadvantage for large-scale simple-cycle gas turbines.

- Smaller CCGT units have lower electrical efficiencies compared to larger units. Units below 20 MW are few and will face close competition with single-cycle gas turbines and reciprocating engines.
- The high air/fuel ratio for gas turbines leads to lower overall efficiency for a given flue gas cooling temperature compared to steam cycles and cogeneration based on internal combustion engines.
- When CCGT plants use the same gas source, an incident of gas supply can cause loss of several power plants.
- High running cost (fuel type and price)
- Should always run at rated load to gain high efficiency
- Exhaust temperature is very high on open cycle operation mode
- Load effected by high relative humidity

Environment

Gas turbines have continuous combustion with non-cooled walls. This means a very complete combustion and low levels of emissions (other than NO_x). Developments focusing on the combustors have led to low NO_x levels. To lower the emission of NO_x further, post-treatment of the exhaust gas can be applied, e.g. with SCR catalyst systems.

Employment

Gas turbines are highly reliant and therefore also low maintenance. Gas turbine technicians needs to be employed to maintain and operate the turbine, but most employments happen during construction of the turbine. One study suggests that natural gas as a technology is among the technologies with fewest employments compared to other technologies at 0.95 jobs per MW (ref. 6)

Research and development perspectives

Gas turbines are a very well-known and mature technology – i.e., category 4.

Increased efficiency for simple-cycle gas turbine configurations has also been reached through inter-cooling and recuperators. Research into humidification (water injection) of intake air processes (HAT) is expected to lead to increased efficiency due to higher mass flow through the turbine.

Additionally, continuous development for less polluting combustion is taking place. Low- NO_x combustion technology is assumed. Water or steam injection in the burner section may reduce the NO_x emission, but also the total efficiency and thereby possibly the financial viability. The trend is more towards dry low- NO_x combustion, which increases the specific cost of the gas turbine.

Continuous research is done concerning higher inlet temperature at first turbine blades to achieve higher electricity efficiency. This research is focused on materials and/or cooling of blades.

Continuous development for less polluting combustion is taking place. Increasing the turbine inlet temperature may increase the NO_x production. To keep a low NO_x, emission different options are at hand or are being developed, i.e., dry low- NO_x burners, catalytic burners etc.

Development to achieve shorter time for service is also being promoted.

Investment cost estimation

As there are no local cases in Ethiopia yet, the investment cost is estimated based on international data available. Furthermore, the projected costs are based on the learning curve approach. The cost might therefore vary from this in reality.

Investment costs [$MUSD_{2019}$/MW]		2018-2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		CCGT: 0.95 SCGT: 0.67	CCGT: 0.9 SCGT: 0.64	CCGT: 0.84 SCGT: 0.59
International data	Danish technology catalogue[2]		CCGT: 0.99 SCGT: 0.67	CCGT: 0.94 SCGT: 0.63	CCGT: 0.90 SCGT: 0.59
	NREL's ATB		CCGT: 0.95 SCGT: 0.67	CCGT: 0.90 SCGT: 0.64	CCGT: 0.85 SCGT: 0.60
	IEA WEO 2019 (average of India and China)[1]	0.63			0.56 (2040)
	IEA-NEA Projected Costs of Generating Electricity 2020	CCGT: 0.96 SCGT: 0.67 (median values)			
Projection	Learning curve - cost trend [%]	-	100%	95%	89%

[1] *IEA WEO, no significant price difference between 2018 and 2020 assumed.*

[2] *The Danish Technology Catalogue reports values for combined heat and power (CHP) plants. Investment costs are higher for CHP plants than for condensing units.*

Examples of current projects

It was not possible to give examples of Ethiopian gas turbines for power production as there are neither installed gas turbine, nor are planned. Therefore, this section covers cases from Nigeria and Tanzania as they are more reliant on natural gas in their energy system.

In Benin, Nigeria, the combined cycle gas plant Azura-Edo power station is being built, and the first phase out of three was finished 6 months ahead of schedule. The cost of the first phase was 900 MUSD for a 450 MW plant. The financing is split between 15 different institutions, where several of them are members of the World Bank Group. When all three phases are concluded, the combined capacity will be 1500MW (ref.7 and 8).

In connection to the cement factory Dangote Cement in Tanzania, a 45 MW gas fired power plant is currently being tested and will provide power to both the cement factory and the residential area nearby. The plant was expected to be fully operational in 2021. The price of the plant is 90 MUDS and will reduce emissions from the cement factory that today is reliant on coal (ref. 9).

References

The description in this chapter is to a great extent from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following are sources are used:

1. Nag, "Power plant engineering", 2009.
2. Ibrahim & Rahman, "Effect of Compression Ratio on Performance of Combined Cycle Gas Turbine", *Int. J. Energy Engineering*, 2012.
3. Mott MacDonald, "UK Electricity Generation Costs Update", 2010.
4. PECC2, "Nhon Trach 2 combined cycle gas turbine power plant basic design report", 2008
5. Collecting from 6 existing CCGT plants include: Phu My 2.2 (2004), Phu My 4 (2005), Nhon Trach 1 (2008), Nhon Trach 2 (2011), Ca Mau 1 (2008), Ca Mau 2 (2008).
6. The challenges of determining the employment effects of renewable energy. Lambert and silva, 2012.
7. Power potentials. Government of Nigeria, 2019.
8. Azura-Edo gas fired, Nigeria, Jon Whiteaker, 2016.
9. "Dangote to test $90m power plant" The East African, 2020

Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Combined Cycle Gas Turbine								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	600	600	600	200	800	200	800		1
Generating capacity for total power plant (MWe)	600	600	600	200	800	200	800		1
Electricity efficiency, net (%), name plate	57	60	61	45	62	55	65		1,3,5,10
Electricity efficiency, net (%), annual average	56	59	60	39	61	54	64		
Forced outage (%)	5	5	5	3	10	3	10		1
Planned outage (weeks per year)	5	5	5	3	8	3	8		1
Technical lifetime (years)	25	25	25	20	30	20	30		1
Construction time (years)	2.5	2.5	2.5	2	3	2	3		1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30	C	1,2
Minimum load (% of full load)	45	30	15	30	50	10	40	A	5
Warm start-up time (hours)	2	1	1	1	3	0.5	2	A	1,5
Cold start-up time (hours)	4	4	4	2	5	2	5		1,5
Environment									
PM 2.5 (mg per Nm^3)	30	30	30						
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A,D	7,8
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	0.95	0.90	0.84	0.65	1.00	0.55	0.90	F,H	1,3,4,10
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	23,500	22,800	22,100	17,600	29,400	16,600	27,600	B	1,3,4
Variable O&M ($/MWh)	2.30	2.23	2.16	1.73	2.88	1.62	2.70	B	1
Start-up costs ($/MWe/start-up)	80	80	80	60	100	60	100	B	6

References:

1 Ea Energy Analyses, Technology Data for Indonesian Power Sector, 2021
2 Vuorinen, A., 2008, "Planning of Optimal Power Systems".
3 IEA, World Energy Outlook, 2015.
4 Learning curve approach for the development of financial parameters.
5 Siemens, 2010, "Flexible future for combined cycle".
6 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
7 Maximum emission from Minister of Environment Regulation 21/2008
8 Danish Energy Agency, 2020, "Technology Catalogue on Power and Heat Generation".
9 Soares, 2008, "Gas Turbines: A Handbook of Air, Land and Sea Applications".
10 IEA, Projected Costs of Generating Electricity, 2020.

Notes:

A Assumed gradidual improvement to international standard in 2050.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Assumed no improvement for regulatory capability.
D Calculated from a max of 400 mg/Nm3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)
E Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide
F Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
H For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

Technology

Technology	Simple Cycle Gas Turbine - large system								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	50	50	50	35	65	35	65		3
Generating capacity for total power plant (MWe)	100	100	100	35	150	35	150		3
Electricity efficiency, net (%), name plate	34	36	40						1,2
Electricity efficiency, net (%), annual average	33	35	39						1,2
Forced outage (%)	2	2	2						
Planned outage (weeks per year)	3	3	3						
Technical lifetime (years)	25	25	25						
Construction time (years)	1,5	1,5	1,5	1,1	1,9	1,1	1,9	B	3
Space requirement (1000 m^2/MWe)	0,02	0,02	0,02	0,015	0,025	0,015	0,025	B	3
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30	C	3,8
Minimum load (% of full load)	20	30	15	30	50	10	40	A	6
Warm start-up time (hours)	0,25	0,23	0,20						3
Cold start-up time (hours)	0,5	0,5	0,5						3
Environment									
PM 2.5 (mg per Nm^3)	30	30	30	30	30	30	30		7
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A,D	3,7
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	0,67	0,64	0,59	0,65	1,20	0,55	1,10	F,G,H	1-5
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	23.200	22.500	21.800	17.400	29.000	16.400	27.300	B	1-5
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)	24	24	24	18	30	18	30	B	6

References:

1 IEA, Projected Costs of Generating Electricity, 2020.
2 IEA, World Energy Outlook, 2019.
3 Danish Energy Agency, 2015, "Technology Catalogue on Power and Heat Generation".
4 Learning curve approach for the development of financial parameters.
5 Energy and Environmental Economics, 2014, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC's 10- and 20-Year Studies".
6 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
7 Maximum emission from Minister of Environment Regulation 21/2008
8 Vuorinen, A., 2008, "Planning of Optimal Power Systems".

Notes:

A Assumed gradidual improvement to international standard in 2050.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Assumed no improvement for regulatory capability.
D Calculated from a max of 400 mg/Nm3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)
E Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide
F The investment cost of an aero-derivative gas turbine will be in the higher end compared to an industrial gas turbine (ref. 5) . Roughly 50% higher.
G Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
H For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

8. DIESEL ENGINE

Brief technology description

A diesel engine is an internal combustion engine (compression ignition system) fuelled with either heavy or light oil. Internal combustion engines (ICEs) represent a well-established technology used in automobiles, trucks, construction equipment, marine propulsion, and backup power applications.

The basic feature of a combustion engine power plant is a combustion engine (compression ignition engine) coupled directly to a generator. Combustion engines can use a wide range of liquid and gaseous fuels. For power plant purposes the most common fuel is different types of oil, especially diesel. However, in recent years gas has also become more widespread as fuel in combustion engines.

In a diesel engine fuel is pumped from a storage tank and fed into a small day tank which supplies the daily need for the engine. Diesel power plants may use different oil products, including heavy fuel oil (or "residual fuel oil") and crude oil. Heavy fuel oil is cheaper than diesel, but more difficult to handle. It has a high viscosity, almost tar-like mass, and needs fuel conditioning (centrifugal separators and filters) and preheating before being injected into the engine.

In an ICE, the expansion of hot gases pushes a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. Each movement of the piston within a cylinder is called a stroke. For power generation, four-stroke engines (intake stroke, compression stroke, power stroke and exhaust stroke) are predominately used.

The temperatures in the engine are very high (1500-2000°C) and therefore a cooling system is required. Water is circulated inside the engine in water jackets and normally cooled in a cooling tower (or by sea water). The waste heat from the engine and from the exhaust gasses may also be recovered for space heating or industrial processes.

It is also an option, to use the waste heat from exhaust gasses in combined cycle with steam turbine generator. Typically, this is only considered relevant in large-scale power stations (50 MW_e or above) with high capacity factors.

Due to relatively high fuel costs, combustion engine power plants using diesel are mainly used in small or medium sized power systems or as peak supply in larger power systems. For combustion engines using gas the fuel costs are typically lower and the engines are therefore more competitive compared to other technologies. In small power systems they can also be used in combination (backup) with renewable energy technologies. Several suppliers offer turnkey hybrid power projects in the range from 10 to 300 MW, combining solar PV, wind power, biomass, waste, gas and/or diesel (ref. 1).

In an idealised thermodynamic process, a diesel engine would be able to achieve an efficiency of more than 60%. Under real conditions, plant net efficiencies are 45-46%. Efficiencies of 50% are reached for combined cycle power plants (ref. 5).

Input
Diesel engines may use a wide range of fuels including crude oil, heavy fuel oil, diesel oil, emulsified fuels (emulsions composed of water and a combustible liquid), and biodiesel fuel. Engines can also be converted to operation on natural gas.

Output
Electricity

Typical capacities
Up to approx. 300 MW_e. Large diesel power plants (>20 MW_e) would often consist of multiple engines in the size of 1-23 MW_e (ref. 5).

Ramping configurations
Combustion engine power plants do not have minimum load limitations and can maintain high efficiency at partial load due to modularity of design – the operation of a subset of the engines at full load. As load is decreased, individual engines within the generating set can be shut down to reduce the output. The engines that remain operating can generate at full load, maintaining high efficiency of the generating set.

Diesel power plants can start and reach full load within 2-15 minutes (under hot start conditions). Synchronization can take place within 30 seconds. This is beneficial for the grid operator when an imbalance between supply and demand begins to occur.

Engines can provide peaking power, reserve power, load following, ancillary services including regulation, spinning and non-spinning reserve, frequency and voltage control, and black start capability (ref. 2, ref. 3).

Advantages/disadvantages
Advantages
- Minimal impact of ambient conditions (temperature and altitude) on plant performance and functionality.
- Fast start-stop.
- High efficiency in part load.
- Modular technology – allowing most of the plant to generate during maintenance.
- Short construction time, example down to 10 months.
- Proven technology with high reliability. Simple and easy to repair.
- Requires less water for cooling.
- Requires fewer operating staff.
- No stand-by losses.
- Less civil engineering work is required, with less space taken up. Can also be constructed near load centre (like in off-grid or rural locations).
- Quick response to load changes

Disadvantages

- Diesel engines cannot be used to produce high-pressure steam (as turbines). Approx. 50% of the waste heat is released at lower temperatures. This heat can be used for fuel or air preheating.
- Expensive fuel.
- Low efficiency/high operational costs.
- High lubrication cost.
- High environmental impact from NO_x and SO_2 emissions.
- Increasing maintenance cost with lower fuel quality.
- Sound pressure level from the engine can be high if no acoustic dampening is integrated.
- Does not work well under overload conditions for a longer period.
- Limited capacity cannot be setup in large sizes.
- Shorter lifetime and requires higher maintenance compared to gas-based systems.

Environment
Emissions highly depend on the fuels applied, fuel type and its content of sulphur.

Emissions may be reduced via fuel quality selection and low emission technologies or by dedicated (flue gas) abatement technologies such as SCR (selective catalytic reduction) systems. Modern large-scale diesel power stations apply lean-burn gas engines, where fuel and air are pre-mixed before entering the cylinders, which reduces NO_x emissions.

With SCR technology, NO_x levels of 5 ppm, vol, dry at 15% O2 can be attained (ref. 5).

Employment
One study by institute for sustainable futures suggest that employments within this technology is comparable with that of gas (ref. 11). As the section about gas suggest in this technology catalogue, the employment rate is 0.95 jobs/MW making it one of the technologies with the lowest employment rate.

Research and development
Diesel engines are a very well-known and mature technology – i.e., category 4.

Short start-up, fast load response and other grid services are becoming more important as more fluctuating power sources are integrated into power grids. Diesel engines have a potential for supplying such services, and R&D efforts are concentrated into this aspect (ref. 6).

Investment cost estimation
Diesel power plants are a mature technology and only gradual improvements are expected. According to the IEA's projections the global installed capacity of oil fired plants will decrease in the future and therefore, even when considering replacement of existing oil power plants, the future market for diesel power plants is going to be moderate. Taking a learning curve approach to the future cost development, this also means that the price of diesel power plants can be expected to remain at the same level as today. Little geographical differences exist as for the price of diesel engines.

Diesel engines may however also run on natural gas and their advantageous ramping abilities compared to gas turbines make them attractive as backup for intermittent renewable energy technologies. This may pave the way for a wider deployment in future electricity markets.

In the data sheet we consider a 100 MW_e diesel fired power plant consisting of 5 units, at 20 MW_e each. All data for a natural gas engine would be similar to this engine type. However, electric efficiency can be expected to be slightly higher (1 %-point) (Ref. 8 and 9) and emissions are lower, NOx: 100-150 g/GJ fuel and PM 2.5: 5-10 gram per Nm^3 (Ref. 8 and 9).

Investment costs [$MUSD_{2019}$/MW]		2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**	0.6	0.57	0.53
International Data	Danish technology catalogue	0.56	0.54	0.51
	Bangladesh Scenario	0.18	0.17	0.16
Projection	Learning curve - cost trend [%]	1	0.95	0.89

Examples of current projects

Table 12: Existing diesel plants in Ethiopia

	Plant Name	Installed capacity (MW)	No. of units	Completion of Construction
1	Dire Dawa	40	4 units (10 MW)	2004
2	Awash7 Kilo	35	10 units (3.5 MW)	2005
3	Kaliti	14	4 units (3.5 MW)	2005

Currently there is no future plan to use new diesel plants. All existing plants are under rehabilitation. To estimate the investment cost of building a new diesel engine, cases from other parts of the world have been examined. A recent 37 MW project on the Faeroe Island has been announced to cost 0.86 mill. $/$MW_e$ (ref 6). This project has been built with strict focus on minimising air pollution, which explains the high investment cost.

References

The description in this chapter is to a great extend from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following sources are used:

1. BWSC, 2017. Hybrid power – integrated solutions with renewable power generation. Article viewed, 3rd August 2017 http://www.bwsc.com/Hybrid-power-solutions.aspx?ID=1341
2. Wärtsila, 2017. Combustion Engine vs. Gas Turbine: Part Load Efficiency and Flexibility. Article viewed, 3rd August 2017 https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-part load-efficiency-and-flexibility
3. Wärtsila, 2017. Combustion Engine vs Gas Turbine: Startup Time https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-Start-up-time
4. Wärtsila, 2011. White paper Combustion engine power plants. Niklas Haga, General Manager, Marketing & Business Development Power Plants https://cdn.wartsila.com/docs/default-source/Power-Plants-documents/reference-documents/White-papers/general/combustion-engine-power-plants-2011-lr.pdf?sfvrsn=2
5. Danish Energy Agency, 2016. Technology Data for Energy Plants, August 2016, https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_energy_plants_-_aug_2016._update_june_2017.pdf
6. BWSC once again to deliver highly efficient power plant in the Faroe Islands. http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206
7. Masrur H., 2020. Analysis of techno-economic-Environmental Sustainability of an isolated micro-grid system located in a remote island of Bangladesh.
8. Danish Energy Agency, 2020, "Technology Data - Generation of Electricity and District Heating"
9. Data delivered by Wartsila, January 2021.
10. Wärtsila, 2020. Global references of internal combustion engine plants delivered by Wärtsila corporation.
11. Institute for sustainable futures. Calculating global energy sector jobs, 2015.Data sheets

Datasheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2019. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Diesel engine (using fuel oil)								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	20	20	20						1
Generating capacity for total power plant (MWe)	100	100	100						
Electricity efficiency, net (%), name plate	46	47	48						1
Electricity efficiency, net (%), annual average	45	46	47	43	47	45	52		1
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						2
Technical lifetime (years)	25	25	25						2
Construction time (years)	1,0	1,0	1,0						2
Space requirement (1000 m^2/MWe)	0,05	0,05	0,05						2
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	100	100	100						8,9,10
Minimum load (% of full load)	6,0	6,0	6,0					A	1,8,9,10
Warm start-up time (hours)	0.05	0.05	0.05						1,8,9,10
Cold start-up time (hours)	0.2	0.2	0.2						8,9,10
Environment									
PM 2.5 (gram per Nm^3)	20	20	20					B; C	3,4
SO_2 (degree of desulphuring, %)	0	0	0					C	3,4
NO_X (g per GJ fuel)	280	280	280					C	3,4
Financial data									
Nominal investment (M$/MWe)	0,60	0,57	0,53	0,55	0,70	0,50	0,65	D	6,7,9-11
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	10.000	9.500	8.900						2,9-11
Variable O&M ($/MWh)	6,5	6,0	5,5						2,9,10
Start-up costs ($/MWe/start-up)	-	-	-						

References:

1 Wärtsila, 2011, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants
2 Danish Energy Agency, 2016, "Technology Data for Energy Plants"
3 Minister of Environment, Regulation 21/2008
4 The International Council on Combustion Engines, 2008: Guide to diesel exhaust emissions control of NOx, SOx, particles, smoke and CO2
5 http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206
6 BWSC once again to deliver highly efficient power plant in the Faroe Islands.
7 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
8 IRENA, Flexibility in Conventional Power Plants, 2019. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019
9 Danish Energy Agency, 2020, "Technology Data - Generation of Electricity and District Heating"
10 Data delivered by Wartsila, January 2021
11 Learning curve approach

Notes:

A 30 % minimum load per unit - corresponds to 6 % for total plant when consisting of 5 units
B Total particulate matter
C Typical diesel exhaut emission according to Ref 3 (average of interval) unless this number exceeds the maximum allowed emission according to Minister of Environment Regulation 21/2008. Both SO2 and particulates are dependant on the fuel composition.
D Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

9. BIOGAS POWER PLANT

Brief technology description

Biogas produced by anaerobic digestion is a mixture of several gases (syngas). The most important part of the biogas is methane. Biogas has a caloric value between 23.3 – 35.9 MJ/m^3, depending on the methane content. The percentage of volume of methane in biogas varies between 50 to 72% depending on the type of substrate and its digestible substances, such as carbohydrates, fats and proteins. If the material consists of mainly carbohydrates, the methane production is low. However, if the fat content is high, the methane production is likewise high. For the operation of power generation or CHP units with biogas, a minimum concentration of methane of 40 to 45% is needed. The second main component of biogas is carbon dioxide. Its share in biogas reaches between 25 and 50% of volume. Other gases present in biogas are hydrogen sulphide, nitrogen, hydrogen, steam and carbon monoxide (ref. 1 and ref. 2).

Examples of expected feedstocks of biogas production in Ethiopia are manure, Jatropha, Castor, croton and related seeds. Biogas production units could also be used for treatment of municipal solid waste. Some of the biomass potential can be converted to biogas.

Anaerobic digestion (AD) is a complex microbiological process in the absence of oxygen used to convert the organic matter of a substrate into biogas. The population of bacteria which can produce methane cannot survive with the presence of oxygen. The microbiological process of AD is very sensitive to changes in environmental conditions, like temperature, acidity, level of nutrients, etc. The temperature range that would give better cost-efficiency for operation of biogas power plants are around 35 – 38°C (mesophilic) or 55 – 58°C (thermophilic). Mesophilic gives hydraulic retention time (HRT) between 25 – 35 days and thermophilic 15 – 25 days (ref. 2).

There are different types and sizes of biogas systems: household biogas digesters, covered lagoon biogas systems and Continuously Stirred Tank Reactor (CSTR) or industrial biogas plants (Figure 44). The last two systems have been largely applied to produce heat and/or electricity (CHP) commercially for own use and sale to customers.

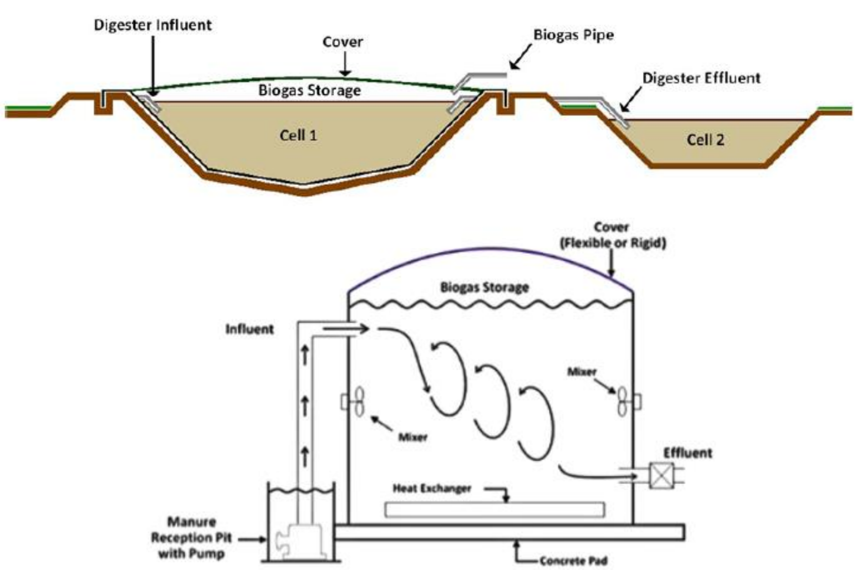

Figure 44: Covered lagoon and CSTR biogas plants (ref.3)

Covered lagoon systems are applied for which the biogas feedstocks are mostly liquid waste. The feedstock is stored in a lake that is covered by an airtight membrane to capture biogas during anaerobic biological conversion processes. In CSTR systems, liquid waste is stored in tanks to capture biogas during the anaerobic biological conversion process. In general, this type of technology has several stirrers in the tank that serves to stir the material that has higher solids content (≥12%) continuously.

The output of biogas depends much on the amount and quality of supplied organic waste. For manure the gas output is typically 14 – 14.5 m^3 methane per tonne, while the gas output typically is 30 – 130 m^3 methane per tonne for industrial waste (ref. 4). Additional biogas storage is required when the consumption of biogas is not continuous. Biogas storage would be beneficial to accommodate when demand is higher or lower than the biogas production.

Biogas from a biodigester is transported to the gas cleaning system to remove sulphur and moisture before entering the gas engine to produce electricity. The excess heat from power generation with internal combustion engines can be used for space heating, water heating, process steam covering industrial steam loads, product drying, or for nearly any other thermal energy need. The efficiency of a biogas power plant is about 35% if it is just used for electricity production. The efficiency can go up to 80% if the plant is operated as combined heat and power (CHP).

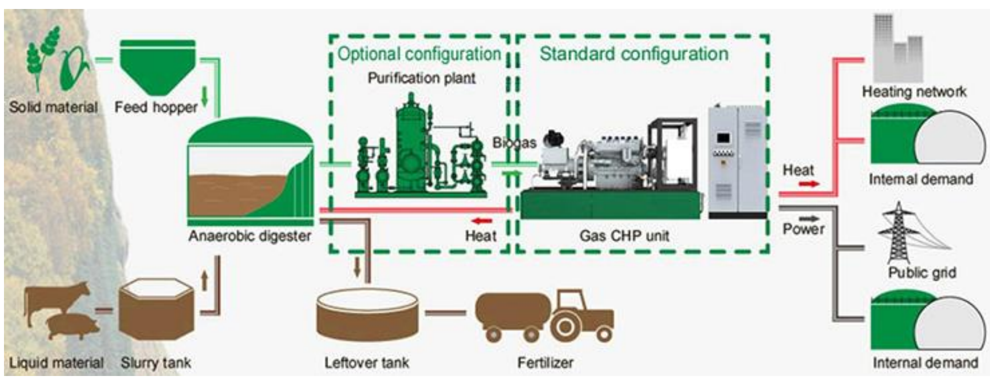

Figure 45: Biogas CHP working diagram (ref. 5)

Input

Bio-degradable organic waste without environmentally harmful components such as, animal manure, solid and liquid organic waste from industry. Sludge from sewage treatment plants and the organic fraction of household waste may also be used.

Output

Electricity and heat.

The data presented in this technology sheet assume that the biogas is used as fuel in an engine, which produces electricity. However, the gas may also be injected into the natural gas grid or used as fuel for vehicles. In this case the gas needs to be treated to comply with the standards of the gas grid. The digested biomass can be used as fertilizer in crop production.

Typical capacities
Medium: 10 – 50 MW.
Small: 1 – 10 MW.

Ramping configurations
Like gas power plants, biogas power plants can ramp up and down. However, there is a biological limit to how fast the production of biogas can change. This is not the case for the plants which have biogas storage. Biogas storage would be beneficial to accommodate when demand is higher or lower than the biogas production.

Advantages/disadvantages
Advantages:
- Renewable energy source.
- The CO2 abatement cost is quite low since methane emission is mitigated.
- Reduced soil and water pollution.
- Saved expenses in manure handling and storage; provided separation is included and externalities are monetized.
- Environmentally critical nutrients, primarily nitrogen and phosphorus, can be redistributed from overloaded farmlands to other areas.
- The fertilizer value of the digested biomass is better than the raw materials. The fertilizer value is also better known, and it is therefore easier to distribute the right amount on the farmlands.
- Compared with other forms of waste handling, biogas digestion of solid biomass has the advantage of recycling nutrients to the farmland – in an economically and environmentally sound way.
- Relatively simple and low-cost technology.

Disadvantages:
- The technology is not very efficient and increasing the efficiency is difficult.
- Using biogas on a large-scale is not economically viable.
- Production can be affected by weather, as in cold climates the process requires heating.
- Biogas contains impurities.
- Methane is prone to explosions.

Environment
Biogas is a CO_2-neutral fuel. Also, without biogas fermentation, significant amounts of the greenhouse gas methane will be emitted to the atmosphere. For biogas plants in Denmark the CO_2 mitigation cost has been determined to approx. 5 € per tonne CO_2-equivalent (ref. 6).

The anaerobic treated organic waste product is almost GHG-free compared to raw organic waste.

Employment
Biogas employs 341.800 people around the world and is one of the renewable technologies with fewest employments according to IRENA (ref 12).
Research and development
Makel Engineering, Inc. (MEI), Sacramento Municipal Utility District, and the University of California, Berkeley developed a homogenous charge compression ignition (HCCI) engine-generator (genset) that efficiently produces electricity from biogas. The design of the HCCI engine-generator set, or "genset," is based on a combination of spark ignition and compression ignition engine concepts, which enables the use of fuels with

very low energy content (such as biogas from digesters) to achieve high thermal efficiency while producing low emissions. Field demonstrations at a dairy south of Sacramento, California show that this low-cost, low-emission energy conversion system can produce up to 100 kW of electricity while maintaining emission levels that meet the California Air Resources Board's (ARB) strict regulations (ref. 8).

Investment cost estimation

Like for biomass plants, the investment cost data for biogas plants highly depend on the feedstock that is gasified. This determines the calorific value of the gas, the amount of impurities (and the need for equipment to remove them) and any special treatment the feedstock needs to receive before the gasification. Hence, in this catalogue the investment cost figures are based on international data, due to the absence of local data availability. Further, the projection is based on the learning curve estimated for biomass power plants.

Investment costs [$MUSD_{2019}$/MW]		2018	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**		**3**	**2.73**	**2.4**
International Data	NREL ATB		4.00	3.85	3.44
	IEA Bioenergy (Task 32)		2.70	2.60	2.60
Projection	Learning curve – cost trend [%]	-	100%	91%	80%

Examples of current projects

In Ethiopia, the use of biogas at large-scale to generate power is still difficult. High investment costs of biogas power plants have so far led to a limited deployment in Ethiopia.

An overview of examples of biogas projects in the world can be found at https://www.biogasworld.com/. (ref. 11). Two examples are:

The Morgan Abattoir Biogas Plant in Springs, South Africa, was put into operation in 2015 and has an estimated yearly production of 1,500,000 m³/yr. It is an industrial plant producing power and heat and the investment cost was 1,500,000 US$.

The Engelskirchen plant in Germany uses yearly 35,000 tons on organic municipal solid waste to produce 3,500,000 m³ of biogas pr. year. The plant was put in operation in 1998 and it has two digesters of each 3,000 m³ and an electricity production capacity of 940 kW.

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Data sheets

The follow pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Biogas power plant								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1						3
Generating capacity for total power plant (MWe)	1	1	1						3
Electricity efficiency, net (%), name plate	35	35	35						4
Electricity efficiency, net (%), annual average	34	34	34						4
Forced outage (%)	5	5	5						1
Planned outage (weeks per year)	5	5	5						1
Technical lifetime (years)	25	25	25						7
Construction time (years)	1.5	1.5	1.5						7
Space requirement (1000 m^2/MWe)	70	70	70						12
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30		11
Minimum load (% of full load)	20	30	15	30	50	10	40		10
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	3.00	2.73	2.40	1.55	4.00	1.3	3.5	B	3,5,8,9
- of which equipment	65	65	65	50	85	50	85		
- of which installation	35	35	35	15	50	15	50		
Fixed O&M ($/MWe/year)	97,000	88,300	77,600	72,800	121,300	58,200	97,000	A	5,7,9
Variable O&M ($/MWh)	0.11	0.1	0.1	0.1	0.1	0.1	0.1	A	6,9
Start-up costs ($/MWe/start-up)									

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Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 25%.

B For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

10. BIOMASS POWER PLANT

Brief technology description

Biomass is organic, meaning it is made of material that comes from living organisms, such as plants, animals, forestry and agriculture residues, and organic compounds of municipal and industrial wastes. Biomass technologies decompose organic matters to release their stored energy in the form of biofuels and bioenergy. Biomass energy is generated from either the combustion of biomass or the anaerobic gas from biomass. The most common biomass materials used for energy are plants, wood, and waste. These are called biomass feedstocks. The energy from these can be transformed into usable energy through direct and indirect means. It can be used to produce electricity or fuels for transport, heating, and cooking. Figure 46 shows the various products from biomass. This chapter focuses on solid biomass for combustion destinated to power generation.

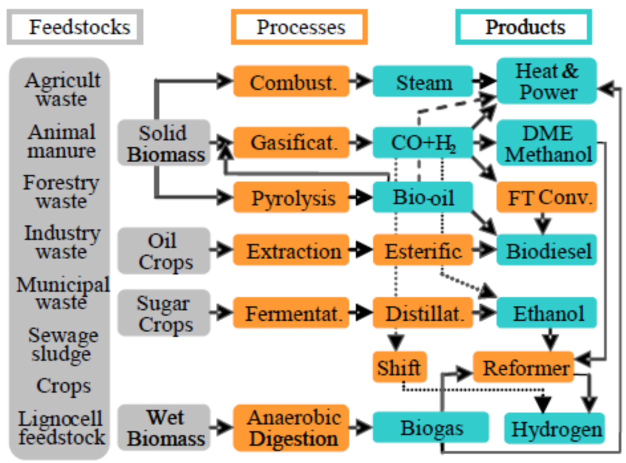

Figure 46: Biomass conversion paths (ref. 1)

The technology used to produce electricity in biomass power plants depends on the biomass resources. Due to the lesser heating value of biomass than coal and the limitations in steam temperature and pressure due the mineral contents of the ash, the electric efficiency is lower compared to coal – typically 15-35% (ref. 2).

Direct combustion of biomass is generally based on the Rankine cycle, where a steam turbine is employed to drive the generator, similar to a coal-fired power plant. A flue gas heat recovery boiler for recovering and preheating the steam is sometimes added to the system. This type of system is well developed, and available commercially around the world. Most biomass power plants today are direct-fired (ref. 3). In direct combustion, steam is generated in boilers that burn solid biomass, which has been suitably prepared (dried, baled, chipped, formed into pellets or briquettes, or otherwise modified to suit the combustion technology) through fuel treatment and a feed-in system. Direct combustion technologies may be divided into fixed bed, fluidized bed, and dust combustion. In dust combustion, the biomass is pulverized or chopped and blown into the furnace, possibly in combination with a fossil fuel (Figure 47).

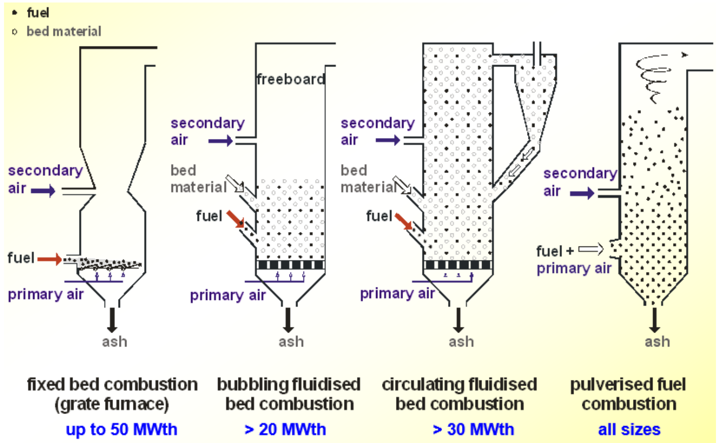

Figure 47: Technologies for industrial biomass combustion (ref. 4)

Co-firing with coal

There are three possible technology set-ups for co-firing coal and biomass: direct, indirect and parallel co-firing (Figure 48). Technically, it is possible to co-fire up to about 20% biomass capacity without any technological modifications; however, most existing co-firing plants use up to about 10% biomass. The co-firing mix also depends on the type of boiler available. In general, fluidized bed boilers can substitute higher levels of biomass than pulverized coal-fired or grate fired boilers. Dedicated biomass co-firing plants can run up to 100% biomass at times, especially in those co-firing plants that are seasonally supplied with large quantities of biomass (ref. 5).

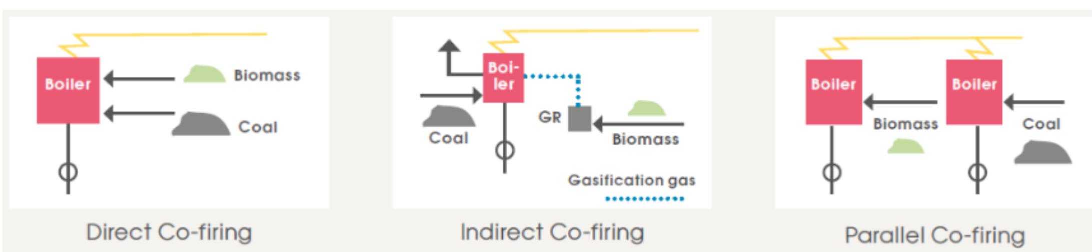

Figure 48: Different biomass co-firing configurations (ref. 6)

Combustion can in general be applied for biomass feedstock with moisture contents between 20 – 60% depending on the type of biomass feedstock and combustion technology.

The total bioenergy availability in Ethiopia was estimated to be 750 PJ per year (46.5% forest residue, 34% crops residue, 18.8% livestock waste, and 0.05% MSW).

Two types of biomass thermal power plants exist in Ethiopia:

1. Simple biomass thermal power plants: all electricity generated is exported to the power grid.
2. Biomass thermal power plants that are cogeneration: meaning that they are captive power plants attached to a factory, typically a sugar factory, and the electricity produced is consumed mainly by that factory, with only surplus power being supplied to the national grid.

Table 13: Heating values of different biomass fuel types (ref. 9)

Type	LHV (GJ/ton)	Moisture (%)	Ash (%)
Straw	12	10	4.4
Wood	8.4 – 17	10 – 60	0.25 – 1.7
Bagasse	7.7 – 8.0	40 – 60	1.7 – 3.8
Coffee husks	16	10	0.6
Maize			
- Cobs	13 – 15	10 – 20	2
- Stalks			3 – 7
Peat	9.0 – 15	13 – 15	1 – 20

Input
Biomass; e.g. residues from industries (wood waste, bagasse etc.), wood chips (collected in forests), straw, and energy crops.

Wood is usually the most favourable biomass for combustion due to its low content of ash and nitrogen. Herbaceous biomass like straw and miscanthus have higher contents of N, S, K, Cl etc. that leads to higher primary emissions of NO_x and particulates, increased ash, corrosion and slag deposits. Flue gas cleaning systems as ammonia injection (SNCR), lime injection, back filters, De NO_x catalysts etc. can be applied for further reduction of emissions.

Typical capacities
Large: bigger than 50 MW_e
Medium: 10 – 50 MW_e.
Small: 1 – 10 MW_e.

Ramping configuration
The plants can be ramped up and down. Medium and small size biomass plants with drum type boilers can be operated in the range from 40-100% load. Often plants are equipped with heat accumulators allowing the plant to be stopped daily.

Advantages/disadvantages
Advantages:
- Mature and well-known technology.
- Burning biomass is considered CO_2 neutral.
- Using biomass waste will usually be cheap.
- Abundant and renewable
- Reduces dependency on fossil fuels
- Reduces landfills
- Biomass production adds a revenue source for manufacturers.

Disadvantages:
- The availability of biomass feedstock is locally dependent.

- Use of biomass can have negative indirect consequences e.g., in competition with food production, nature/biodiversity.
- In the low capacity range (less than 10 MW) the scale of economics is quite considerable.
- When burning biomass in a boiler, the chlorine and sulfur in the fuel end up in the combustion gas and erode the boiler walls and other equipment. This can lead to the failure of boiler tubes and other equipment, and the plant must be shut down to repair the boiler.
- Fly ash may stick to boiler tubes, which will also lower the boiler's efficiency and may lead to boiler tube failure. With furnace temperatures above 1000°C, empty fruit bunches, cane trash, and palm shells create more melting ashes than other biomass fuels. The level for fused ash should be no more than 15% to keep the boiler from being damaged (ref. 9).

Environment

The main ecological footprints from biomass combustion are persistent toxicity, climate change, and acidification. However, the footprints are small (ref. 10).

Employment

According to one study the employment rate for biomass pr MW is within an interval of 0.78 jobs/MW and 2.84 jobs/MW, making it one of the technologies with the highest employment rate (ref. 11). It should be noted that this employment rate varies from region to region.

Internationally, according to IRENA estimates, solid biomass has generated 764,300 jobs (ref. 12).

Research and development

Biomass power plants are a mature technology with limited development potential (category 4).

Direct, traditional uses of biomass for heating and cooking applications rely on a wide range of feedstock and simple devices, but the energy efficiency of these applications is very low because of biomass moisture content, low energy density (Figure 49), inefficient combustion and the heterogeneity of the basic input. A range of pre-treatment and upgrading technologies have been developed to improve biomass characteristics and make handling, transport, and conversion processes more efficient and cost effective. Most common forms of pre-treatment include drying, pelletization and briquetting, torrefaction and pyrolysis, where the first two are by far the most commonly used.

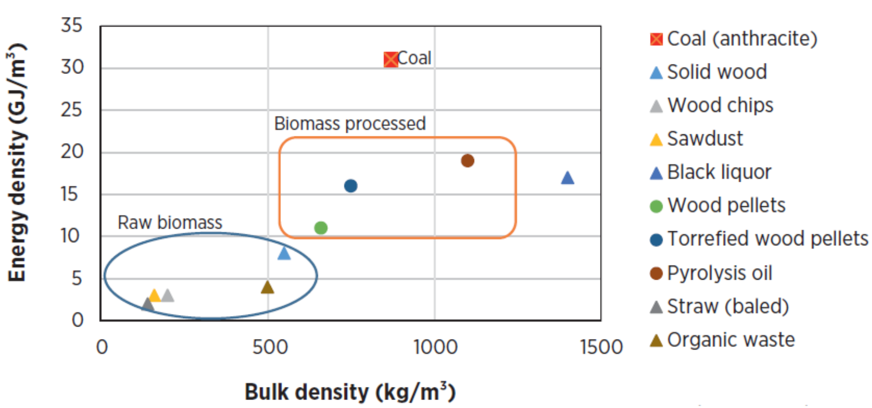

Figure 49: Energy density of biomass and coal (ref. 11)

MSW incineration, anaerobic digestion, landfill gas, combined heat and power and combustion are examples of biomass power generation technologies which are already mature and economically viable. Biomass gasification and pyrolysis are some of the technologies which are likely to be developed commercially in the future.

Gasifier technologies offer the possibility of converting biomass into a producer gas, which can be burned in simple or combined-cycle gas turbines at higher efficiencies than the combustion of biomass to drive a steam turbine. Although gasification technologies are commercially available, more needs to be done in terms of R&D and performance demonstration to promote their widespread commercial use (Figure 50).

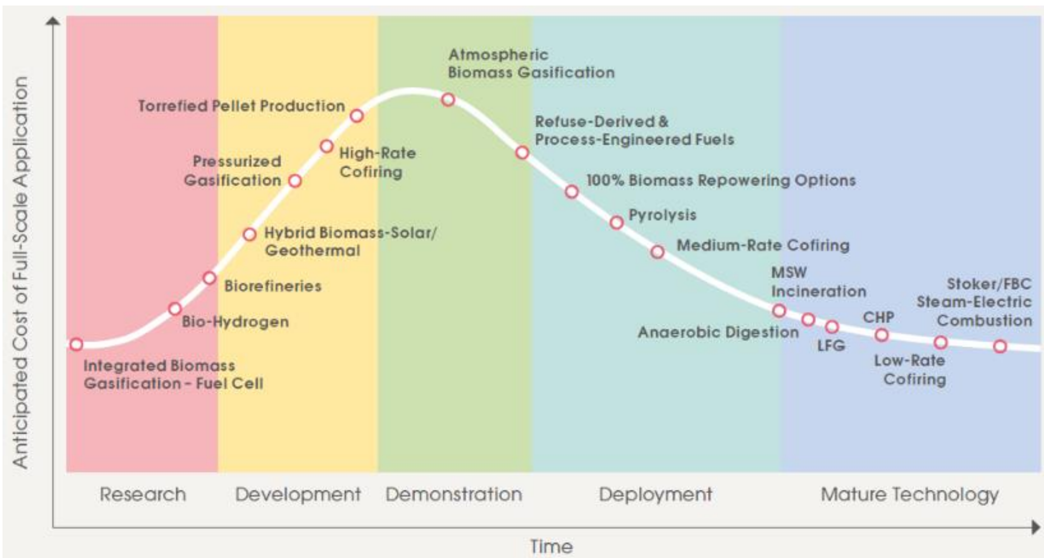

Figure 50: Biomass power generation technology maturity status (ref. 12)

Biomass pyrolysis is the thermal decomposition of biomass in the absence of oxygen. The products of decomposition are solid char, a liquid known as bio-oil or pyrolysis oil and a mixture of combustible gases. The relative proportions of solid, liquid, and gaseous products are controlled by process temperature and residence time, as indicated in Table 14.

Bio-oil has a low heating value of about 16 MJ/kg and can after suitable upgrading be used as fuel in boilers, diesel engines and gas turbines for electricity or CHP generation. As a liquid with higher energy density than the solid biomass from which it is derived, bio-oil provides a means of increasing convenience and decreasing costs of biomass transport, storage, and handling.

Table 14: Phase makeup of biomass pyrolysis products for different operational modes (ref. 13)

Mode	Conditions	Composition		
		Liquid	Char	Gas
Fast pyrolysis	Moderate temperature, short residence time	75%	12%	13%
Carbonization	Low temperature, very long residence time	30%	35%	35%
Gasification	High temperature, long residence time	5%	10%	85%

Investment cost estimation

The investment costs of biomass power plants largely depend on the type of feedstock – size, calorific value, chemical composition etc. – as this affects the pre-treatment processes. Economy of scale also plays an important role. Here, the estimated investment cost for 2020 is based empirically on the international data, and the projections is done using the learning curve approach for biomass power production.

Investment costs [$MUSD_{2019}$/MW]		2019	2020	2030	2050
Catalogues	**Technology Catalogue for Ethiopia (2020)**		**2.9**	**2.64**	**2.32**
Ethiopian data					
International data	Danish technology catalogue**		1.81	1.72	1.67
	NREL ATB		4.00	3.85	3.44
	IEA Bioenergy (Task 32)		2.70	2.60	2.60
	EIA	2.83			
	IEA-NEA Projected Costs of Generating Electricity	2.5 (mean)			
Projection	Learning curve – cost trend [%]	-	100%	91%	80%

*** The catalogue reports values for CHP plants. Assuming a backpressure ratio of 0.15, a condensing equivalent is here calculated based on a full-plant electric efficiency of 31%.*

Examples of current projects

Most plants in Ethiopia are cogeneration type. As discussed earlier, cogeneration means that the electricity is generated by a captive power plant attached to a factory, typically a sugar factory in Ethiopia, and the electricity produced is consumed mainly by that factory, with only surplus power being supplied to the national grid.

The production of sugar and bioethanol from sugarcane leaves over biomass waste: bagasse. The production of sugar and bioethanol requires thermal and electrical energy, both which are provided through the combustion of bagasse. The excess electrical power that is not needed for the production processes is then delivered to the national power grid. Table 15 provides details of the industrial cogeneration plants in Ethiopia.

Table 15: Details of the industrial cogeneration plants in Ethiopia

ICS Thermal plant	Location	Fuel	Thermal capacity (MWth)	Installed capacity (MWe)	Max. net exports (MWe)	Status	Note
Adi Gudem Industrial	Adi Gudem	Gas (CCGT)	500	135	365	Under Construction	IPP
Wonji-Shoa Sugar	Adama	bagasse	30	9	21		
Metehara Sugar	Metahara	bagasse	9	9	0		
Finchaa Sugar	Fincha	bagasse	30	18	12		
Kessem Sugar	Enjibara	bagasse	26	10	16		
Tendaho Sugar	Asaita	bagasse	60	22	38		
Omo Kuraz I Sugar	Kuraz	bagasse	45	16	29		
Omo Kuraz II Sugar	Kuraz	bagasse	60	20	40		
Omo Kuraz III Sugar	Kuraz	bagasse	60	20	40		
Omo Kuraz V Sugar	Kuraz	bagasse	120	40	80	Under Construction	
Total					**647**		
Total operational					**167**		

The Ethiopian sugar factories are state-owned, and they are sometimes under construction for many years and don't necessarily deliver sugar – or electricity. Bagasse is only available from October to May during and after the harvesting of sugarcane. Therefore, the operation of the plants (and their cogeneration facilities) is limited to these months. Given such conditions, the capacity factor of the plants has low chances to be above 0.5.

In addition, other thermal biomass power plants are planned to be constructed in Anjibara woreda (close to the Kessem sugar factory) to make use of the Devil's Tree other than bagasse in the campaign gap from May to October.

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Data sheets

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

The data sheet describes plants used for production of electricity. These data do not apply for industrial plants, which typically deliver heat at higher temperatures than power generation plants, and therefore they have lower electricity efficiencies. Also, industrial plants are often cheaper in initial investment and O&M, among others because they are designed for shorter technical lifetimes, with less redundancy, low-cost buildings etc.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Biomass power plant (smal plant)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	25	25	25	1	50	1	50		1,5
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1,5
Electricity efficiency, net (%), name plate	32	32	32	25	35	25	35		1,3,7
Electricity efficiency, net (%), annual average	31	31	31	25	35	25	35		1,3,7
Forced outage (%)	7	7	7	5	9	5	9	A	1
Planned outage (weeks per year)	6	6	6	5	8	5	8	A	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	8,10
Construction time (years)	2	2	2	2	3	2	3	A	10
Space requirement (1000 m^2/MWe)	35	35	35	26	44	26	44	A	1,9
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10						3
Minimum load (% of full load)	30	30	30						3
Warm start-up time (hours)	0,5	0,5	0,5						3
Cold start-up time (hours)	10	10	10						3
Environment									
PM 2.5 (mg per Nm^3)	12,5	12,5	12,5						3
SO_2 (degree of desulphuring, %)	0,0	0,0	0,0						3
NO_X (g per GJ fuel)	125	125	125						3
CH_4 (g per GJ fuel)	0,9	0,9	0,9						3
N_2O (g per GJ fuel)	1,1	1,1	1,1						3
Financial data									
Nominal investment (M$/MWe)	2,90	2,64	2,32	1,30	4,00	1,7	3,5	B,C	4-8,11
- of which equipment	65	65	65	50	85	50	85		1,2
- of which installation	35	35	35	15	50	15	50		1,2
Fixed O&M ($/MWe/year)	47.600	43.800	38.100	35.700	59.500	28.600	47.600	A	4,5,8,11
Variable O&M ($/MWh)	3,0	2,8	2,4	2,3	3,8	1,8	3,0	A	5,11
Start-up costs ($/MWe/start-up)									

References:

1 Ea Energy Analyses, Technology Data for Indonesian Power Sector, 2021

2 ASEAN Centre of Energy, 2016, "Levelised cost of electricity generation of selected renewable energy technologies in the ASEAN member states".

3 Danish Energy Agency and COWI, 2017, "Technology vatalogue for biomass to energy".

4 IRENA, 2015, "Renewable power generation cost in 2014"

5 IFC and BMF, 2017, "Converting biomass to energy - A guide for developmers and investors".

6 EIA 2020, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020

7 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

8 PKPPIM, 2014, "Analisis biaya dan manfaat pembiayaan investasi limbah menjadi energi melalui kredit program", Center for Climate Change and Multilateral Policy Ministry of Finance Indonesia.

9 India Central Electricity Authority, 2007, "Report on the Land Requirement of Thermal Power Stations".

10 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

11 Learning curve approach for the development of financial parameters.

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 25%.

B Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

C For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

11. NUCLEAR POWER

Brief technology description

Nuclear energy has been used for civil purposes since the mid-1900s. Progress in nuclear engineering has brought about significant changes in the plant layout ever since. Different concepts have been tested and used around the world, building on national and regional research programmes. Nuclear power plants are not a standardized technology, as geopolitical reasons and historical legacy make nuclear research a national or regional matter.

In broad terms, nuclear energy can be obtained by:

- Splitting the *nuclei* of specific, heavy chemical elements (nuclear fission)
- Combining the nuclei of light chemical elements (nuclear fusion)

All power plants operating in the world are of the fission type. Nuclear fusion, which resembles the combination of atoms in the Sun, has been researched for decades, but no stable reactivity has yet been achieved. This is primarily due to the extreme thermo-physical conditions in the reactor, which require extensive research in control, materials and physics.

All fission power plants build on the same concept (Figure 51). Heavy atom nucleus' components (protons, neutrons) are tied together by nuclear forces. Elements with atomic number (Z) over 83 are unstable and decay naturally into elements with a higher binding energy. This occurs because the resulting elements have a higher stability than the original element.

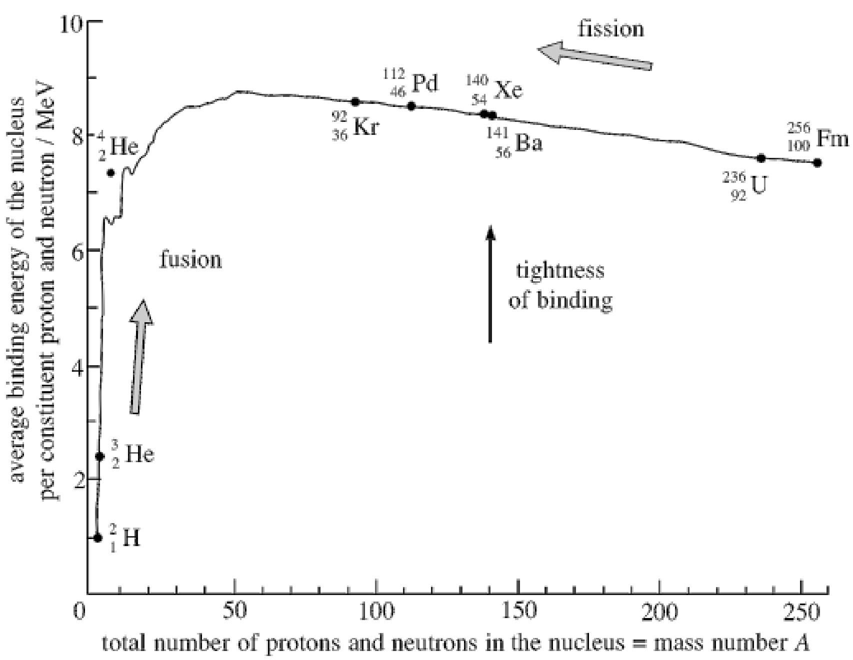

Figure 51: Nuclear energy binding graph (ref 1).

Fission can also be *induced* by supplying energy to such unstable elements, which in turn release an amount of energy equal to the binding energy of the original element. Induced fission is at the heart of nuclear power plant engineering. The activation energy, which is kinetic energy provided by mobile neutrons hitting the nuclei of selected heavy elements (such as ^{235}U), catalyses a reaction such as the following:

$$^{1}_{0}n + \ ^{235}_{92}U \rightarrow \ ^{141}_{56}Ba + \ ^{92}_{36}Kr + 3\,^{1}_{0}n + energy$$

^{235}U is one of the fissile elements, since it sustains the chain reaction: for every uranium-235 atom splitting, three mobile neutrons *n* are released, which in turn go on hitting other 235-uranium atoms. Energy is released in the form of heat, later used in the power cycle.

Nuclear reactors are designed to sustain and keep a stable reactivity. In the *core*, three key components serve this purpose:

- The fissile material (e.g., uranium-235). It is contained in rods, which need to be periodically replaced as the core gets short of fissile material (fuel cycle).
- The control elements, typically rods, which can be lowered or lifted to regulate reactivity. Rods are made of a certain chemical element which inhibits reactivity by absorbing neutrons, usually boron steel.
- The moderator, that ensures the neutrons released from the fission have the right amount of energy to hit other fissile materials. In fact, neutrons released in a fission reaction have a kinetic energy that is too high to obtain stable reactivity. The effect is a decrease in the likelihood of neutrons hitting other fissile material. To increase it, neutrons need to collide with the moderator. The moderator also carries away the thermal energy released by the reactions, thereby acting as a cooling agent.

Other components of a nuclear reactor are:

- The coolant is a fluid circulating through the core, responsible for transferring the heat from it.
- The pressure vessel, usually a robust steel vessel containing the reactor core and moderator/coolant. It may also be a series of pressure tubes holding the fuel and conveying the coolant through the surrounding moderator.

Fission power plants are usually classified by the core design. The most common reactors are:

- Pressurized water reactors (PWR), where the moderator is water kept at high-pressure to prevent vaporization (Figure 52).
- Boiling water reactors (BWR), where the moderator is water turning into steam as it absorbs heat in the core (Figure 53).

In both cases, water as a moderator can be either heavy or light, depending on the hydrogen isotope. Nowadays, most commercial reactors are of the types above. Nevertheless, other moderators and core designs have been used since the 1950s but have been progressively abandoned.

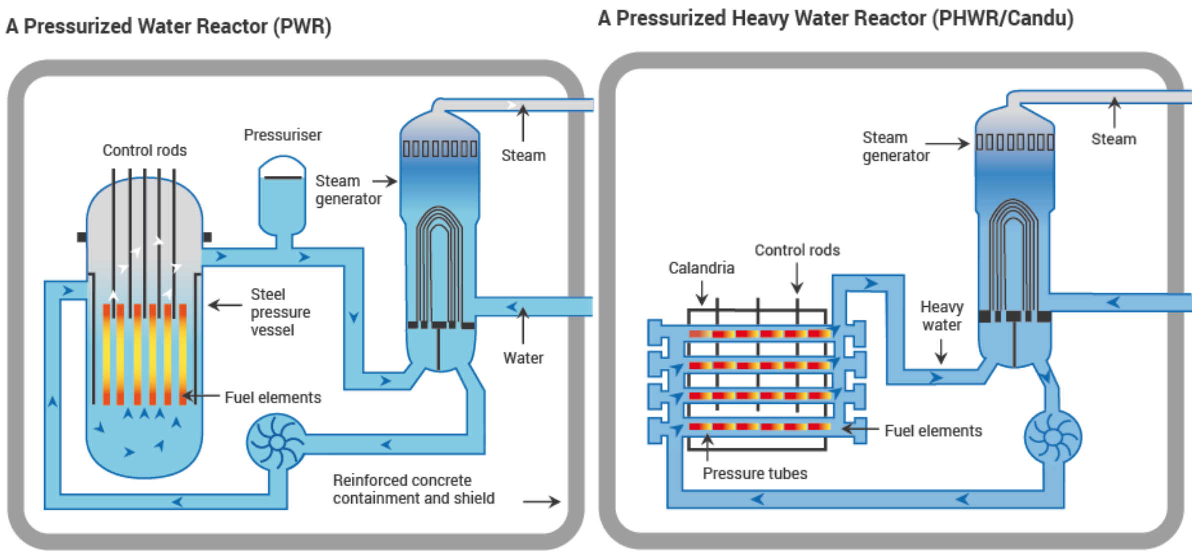

Figure 52: PWR schemes (ref. 2).

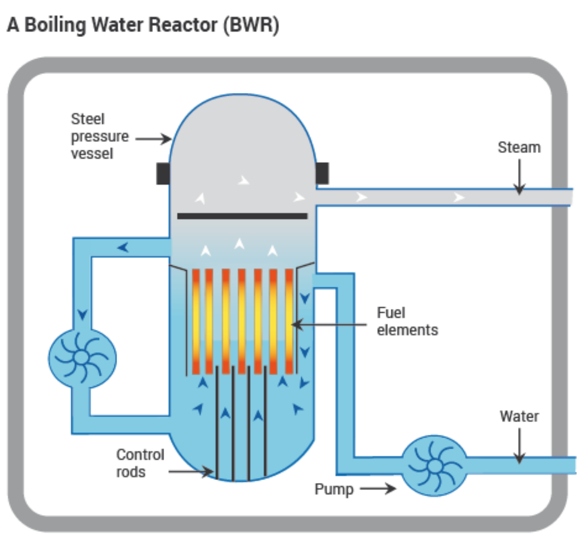

Figure 53: BWR scheme (ref. 2).

In PWRs, the pressurized hot water is turned into steam in a steam generator, which powers a Rankine cycle for electricity production. Unlike BWRs, there exist two circuits (primary and secondary): moderator and working fluid in the power cycle are distinct.

There are several other reactor designs, which are being operated or are operable, are summarised in Table 16.

Table 16: Nuclear reactor types currently under operation or operable (ref 2).

Nuclear power plants in commercial operation or operable

Reactor type	Main countries	Number	GWe	Fuel	Coolant	Moderator
Pressurised water reactor (PWR)	USA, France, Japan, Russia, China, South Korea	301	286	enriched UO_2	water	water
Boiling water reactor (BWR)	USA, Japan, Sweden	64	65	enriched UO_2	water	water
Pressurised heavy water reactor (PHWR)	Canada, India	48	24	natural UO_2	heavy water	heavy water
Advanced gas-cooled reactor (AGR)	UK	14	8	natural U (metal), enriched UO_2	CO_2	graphite
Light water graphite reactor (LWGR)	Russia	12	8.4	enriched UO_2	water	graphite
Fast neutron reactor (FBR)	Russia	2	1.4	PuO_2 and UO_2	liquid sodium	none
TOTAL		441	393			

Nuclear power plants are also classified based on their performance, cost and safety. In this classification, nuclear power plants belong to a specific *generation*:

- *Generation I* reactors (1950s-1960s) were the first commercial reactors. The design differed from country to country and the reactor could be moderated in different manners (water, gas etc.). No Generation I reactor is still in operation.
- *Generation II* reactors (1970s-2000s) are essentially water-cooled and moderated. They can be of the PWR or BWR type. An exception is the AGR graphite-moderated reactor used in the UK. This generation of reactors are more efficient, reliable and safe than Generation I reactors.
- *Generation III* reactors (2010s-) feature safety and design improvements with respect to Generation II reactors and are characterized by an extended lifetime (up to 60 years). They are also conceived to have longer fuel cycles, minimizing downtime.

The power cycle is normally a subcritical Rankine cycle. The efficiency of the cycle depends on the steam characteristics. The layout of the power cycle is kept simple to contain the investment cost of the power plant. In some cases, nuclear plants have also been used for heat production. However, given the high costs of nuclear energy, this is not common, as electricity is more valued as a commodity.

Typical capacities

Due to the high initial investment, modern power plant capacities are generally big enough to benefit from economy of scale (more than 1000 MW). Typically, a power plant is constituted by several reactors. In some cases, the installed capacity tops 5000 MW.

Ramping configurations

Nuclear power plants are characterized by high investment and operational costs. Therefore, they are usually run in base load mode. However, nuclear power plants are able to operate over wide ranges in many countries due to the increasing penetration of renewables. Modern reactors are able (and, in most cases, need) to adjust their functioning to follow up on scheduled or unscheduled load changes, either directly on system operators' requests or via power price dynamics. In Europe, it is a requirement that nuclear power plants are capable of daily cycling between 50% and 100% of nominal load, with a ramping rate of 3-5% per minute. Most modern nuclear power plants (II+/III generation) can safely lower their production to 25% the nominal load.

Advantages/disadvantages

Advantages:

- Well-established technology
- Flexible operations (Reliable in operation)
- Despite past accidents, nuclear power plants are a relatively safe technology
- High energy density in terms of area required.
- Low carbon emissions. Does not emit greenhouse gases once operational.
- Lower operating cost compared to many other technologies.
- Fuel transportation cost is low
- Consumes very small quantity of fuel
- Large fuel storage facility is not required
- Production level is usually not affected by weather conditions
- Nuclear power plants are well suited to meet large power demands as they have a high efficiency and load factors (80 to 90%)
- The nuclear power plants, besides producing large amount of power, produce valuable fissile material which is gathered when the fuel is replenished

Disadvantages:

- Fissile materials (normally uranium) only available in selected countries on Earth.
- Operation patterns conditioned by refuelling (fuel cycles)
- Limited locations suited for power plant construction. Requirements: proximity to load centres, rivers or the sea to operate the condenser, away from seismic areas.
- Public acceptance issues
- Geopolitical issues
- During extreme events, safe operations have not always been guaranteed. Possibility of nuclear disaster.
- High initial capital cost.
- The maintenance cost is always high (due to lack of standardisation and high salaries of the trained personnel in this field of specialisation)
- Handling of nuclear wastes and overall safety is a major concern.
- Decommissioning nuclear power plants is a long and expensive process.

Environment

On a life-cycle basis, nuclear power emits just a few grams of CO_2 equivalent per kWh of electricity produced. A median value of 12g CO_2 equivalent/kWh has been estimated for nuclear, which is relatively low as compared to other power generation technologies (Figure 54).

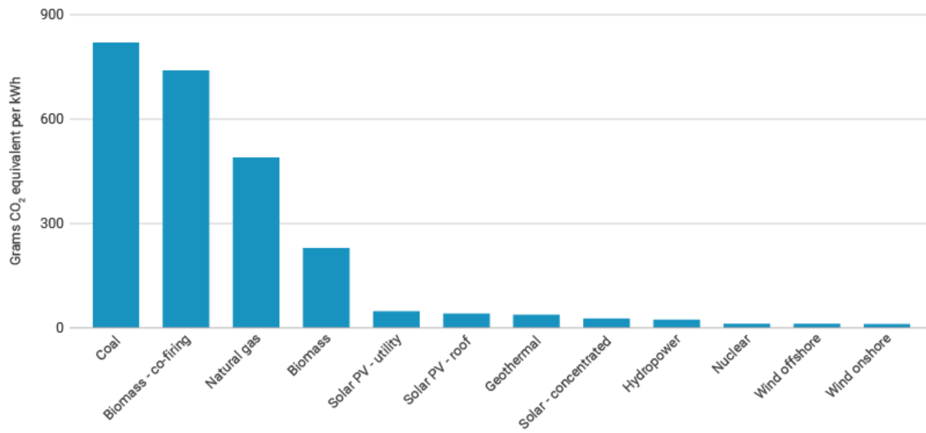

Figure 54: Average life-cycle CO2 equivalent emissions (ref 2).

In terms of land use as well, nuclear power plants take up the least space compared to other technologies due to their high energy density. Another environmental aspect relevant to electricity production technologies is the use of water (depicted in Figure 55) which is becoming a scarce and valuable resource. In the Ethiopian context as well, water is a critical resource. Nuclear plants require high quantities of water for cooling and waste disposal.

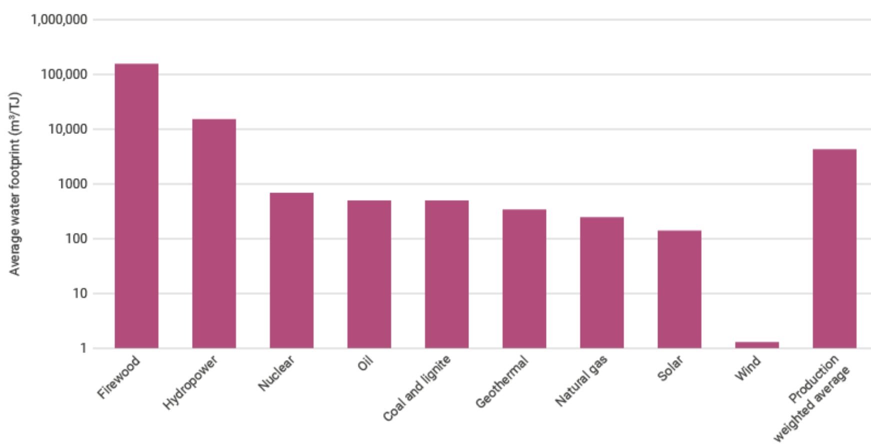

Figure 55: Water consumption per unit of electricity and heat produced (2008-2012) (ref 2).

Handling of the radioactive waste is one of the most significant environmental risks. Exposure to certain high levels of radiation, such as that from high level radioactive waste, can even cause death. Radiation exposure can also cause cancer, birth defects, and other abnormalities, depending on the duration of exposure, amount of radiation, and the decay mechanism. High-level radioactive waste from nuclear reactors can be hazardous for thousands of years.

Radioactive waste includes any material that is either intrinsically radioactive, or has been contaminated by radioactivity, and that is deemed to have no further use. Every radioactive particle has a half-life – the time taken for half of its atoms to decay, and thus for it to lose half of its radioactivity. Radioactive particles with long half-lives tend to be easier to handle. Eventually all radioactive waste decays into non-radioactive elements. The more radioactive an isotope is, the faster it decays.

Radioactive waste is produced at all stages of the nuclear fuel cycle. The fuel cycle involves the mining and milling of uranium ore, its processing and fabrication into nuclear fuel, its use in the reactor, its reprocessing, the treatment of the used fuel taken from the reactor, and finally, disposal of the waste. Whilst waste is produced during mining and milling and fuel fabrication, the majority (in terms of radioactivity) comes from the actual 'burning' of uranium to produce electricity. Radioactive waste is typically classified as either low-level (LLW), intermediate-level (ILW), or high level (HLW), dependent, primarily, on its level of radioactivity.

The waste can be temporarily treated/stored on-site at the production facility using a number of methods, such as vitrification, ion exchange or synroc. Initial treatment prepares the waste for transport and inhibits damage in the short-term. However, long-term management solutions for nuclear waste are critical to reduce the hazards of nuclear power. Specific long-term management methods include geological disposal, transmutation, waste reuse, and space disposal.

Employment

A study on employment generated by the nuclear power sector, based on plants in OECD countries, suggested that a 1000 MWe plant leads to (ref. 3):

- Direct employment during a ten-year period of site preparation and construction of some 1200 professional and construction staff.
- Over a 50-year operating period, approximately 600 administrative, operation and maintenance, and permanently contracted staff are employed annually.
- Once the reactor is shut down, a further 500 people are employed annually over a ten-year period of decommissioning. In addition, over a period of about 40 years, 80 employees manage nuclear waste.

In addition, several jobs are created through indirect employment for the nuclear supply chain. Therefore, the total employment over the life cycle of a 1000 MWe nuclear power reactor is therefore estimated to be ~3000 jobs.

However, these statistics need to be taken in the context of Ethiopia’s existing labour market and supply chain.

Research and development

The next generation of nuclear reactors are categorised as Generation IV. Designs for generation IV are not expected to be operational before the mid-2020s. There are seven designs being considered as generation IV. These are under development by the GIF (Generation IV International Forum) an international collective representing governments of 13 countries where nuclear energy is significant now and seen as vital for the future. The different reactors are summarised in Table 17.

Table 17: Generation IV reactors (ref. 2).

Generation IV reactor designs under development by GIF

	Neutron spectrum (fast/thermal)	Coolant	Temperature (°C)	Pressure*	Fuel	Fuel cycle	Size (MWe)	Use
Gas-cooled fast reactors	fast	helium	850	high	U-238 +	closed, on site	1200	electricity & hydrogen
Lead-cooled fast reactors	fast	lead or Pb-Bi	480-570	low	U-238 +	closed, regional	20-180** 300-1200 600-1000	electricity & hydrogen
Molten salt fast reactors	fast	fluoride salts	700-800	low	UF in salt	closed	1000	electricity & hydrogen
Molten salt reactor - **advanced high-temperature reactors**	thermal	fluoride salts	750-1000		UO_2 particles in prism	open	1000-1500	hydrogen
Sodium-cooled fast reactors	fast	sodium	500-550	low	U-238 & MOX	closed	50-150 600-1500	electricity
Supercritical water-cooled reactors	thermal or fast	water	510-625	very high	UO_2	open (thermal) closed (fast)	300-700 1000-1500	electricity
Very high temperature gas reactors	thermal	helium	900-1000	high	UO_2 prism or pebbles	open	250-300	hydrogen & electricity

* high = 7-15 MPa
\+ = with some U-235 or Pu-239
** 'battery' model with long cassette core life (15-20 yr) or replaceable reactor module.

Additionally, more than a dozen (Generation III) advanced reactor designs are in various stages of development. One of these is called Advanced Boiling Water Reactor, a few of which are now operating with others under construction. The best-known radical new design has the fuel as large 'pebbles' and uses helium as coolant, at very high temperature, possibly to drive a turbine directly. Considering the closed fuel cycle, Generation I-III reactors recycle plutonium (and possibly uranium), while Generation IV are expected to have full actinide recycle. Many advanced reactor designs are for small units – under 300 MWe – and in the category of small modular reactors (SMRs), since several of them together may comprise a large power plant, may be built progressively.

Investment cost estimate

The overnight capital cost for a nuclear plant is dependent on various factors ranging from plant design, equipment, labour, and construction. As Ethiopia is yet to have a nuclear power plant, it is difficult to estimate what specific costs would be for the local context. Therefore, the investment cost estimate here takes into consideration the financial data from various sources. The value for 2020 is set taking into account this global context and also under the consideration that the plant to be set up would most likely be using a PWR (pressurised water reactor). This is because PWR is the most commonly used technology as seen in Table 16. For the projected values till 2050, the learning curve approach is employed, which considers the global capacity development estimates as per the IEA's WEO19, as discussed in the appendix. The data is summarised in the table below.

Investment costs [$MUSD_{2019}$/MW]			2019	2020	2030	2050
Catalogues	**Technology catalogue for Ethiopia (2021)**			**5**	**4.8**	**4.45**
International Data	NREL		6.3	6.18	5.9	5
	IEA WEO19 (Average of USA and EU)	(Average of USA and EU)	6			4.6 (2040)
		(Average of China and India)	2.7			2.7 *(2040)*
	IEA PCOG		3.4 (2.3 to 7)			
	EON		4.7 (PWR) 2.08 to 6 (advanced)			
Projection	Learning curve – cost trend [%]			1.0	0.96	0.89

Examples of current projects

Koeberg Nuclear Power Station, South Africa: This is the only nuclear power station in Africa and has a pressurised water reactor (PWR) design. There are two units of 970 MW, making a total installed capacity of 1940 MW. Construction of Koeberg began in 1976 and Unit 1 was synchronised to the grid on 4 April 1984, with Unit 2 following suit on 25 July 1985. The plant has an average availability over the last 3 years of 79.7% and an average production over the last 3 years of 12 715 GWh (ref 7).

While nuclear technology is yet to be established in Ethiopia, developments like the Ethiopian Nuclear Technology Development Institute and collaboration with Russia, will play key roles in the future of nuclear energy in Ethiopia.

References

The following sources are used:

1. The Open University, http://www.met.reading.ac.uk/pplato2/h-flap/phys9_3.html
2. World Nuclear Association, Information Library, https://www.world-nuclear.org/information-library.aspx
3. NEA and IAEA joint report, *Measuring Employment Generated by the Nuclear Power Sector*, 2018
4. NREL 2020 *Annual Technology Baseline*
5. IEA, *World Energy Outlook*, 2019
6. Energy Options Network, *What will advanced Nuclear Power Plants Cost?* 2016
7. Eskom, www.eskom.co.za.

Data sheets
The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology

Technology	Nuclear power plant - PWR								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1000	1000	1000						
Generating capacity for total power plant (MWe)	2000	2000	2000					B	
Electricity efficiency, net (%), name plate	36	42	50					D	3
Electricity efficiency, net (%), annual average	33	38	45					D	3
Forced outage (%)	5%	4%	3%					C	2
Planned outage (weeks per year)	8	6	5						2
Technical lifetime (years)	60	60	80						3
Construction time (years)	7	6	6	4	10	4	10		3,4
Space requirement (1000 m^2/MWe)	0,003	0,003	0,003	0,001	0,004	0,001	0,004	E	8,9
Additional data for non thermal plants									
Capacity factor (%), theoretical	85	87	90	75	93	75	93		3,4,6
Capacity factor (%), incl. outages	85	87	90	75	93	75	93		3,4,6
Ramping configurations									
Ramping (% per minute)	4	5	5					A	1
Minimum load (% of full load)	25	25	25					A	1
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)	-	-	-						
SO_2 (degree of desulphuring, %)	-	-	-						
NO_X (g per GJ fuel)	-	-	-						
CH_4 (g per GJ fuel)	-	-	-						
N_2O (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	5,00	4,80	4,45	2,00	7,00	2,00	7,00	F	4,5,6,7, 10
- of which equipment	40%	40%	40%						3,7
- of which installation	60%	60%	60%						3,7
Fixed O&M ($/MWe/year)	127.000	122,00	113.000					G	4,5,6,7
Variable O&M ($/MWh)	2,40	2,30	2,20					G	4,5,6,7
Start-up costs ($/MWe/start-up)									

References:

1 Nuclear Energy Association, *Technical and economic aspects of load following with nuclear power plants*, 2011.
2 IEAE, *Nuclear Power Reactors in the World*, 2019.
3 World Nuclear Association, https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/nuclear-power-reactors.aspx
4 IEA-NEA, *Projected Costs of Generating Electricity*, 2020
5 NREL 2020 Annual Technology Baseline
6 IEA, World Energy Outlook, 2019
7 Energy Options Network, What will advanced Nuclear Power Plants Cost?
8 US Dept. of Energy, Office of Nuclear Energy, The ultimate fast facts guide to Nuclear Energy
9 STRATA, The Footprint of Energy: Land use of US Electricity Production, 2017
10

Notes:

A Ramping and minimum load are constrained by the core stability. Minimum requirements are usually set by the regulation.
B A two-unit configuration is typical in nuclear power plants, but more units can be combined.
C % of yearly hours with forced outage
D Generation IV reactors are expected to achieve efficiencies well above 45%. In the future, nuclear reactors are likely to run often at partial load - thus the gap between nameplate and net efficiency
E Nuclear power plants have a very high energy density in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns
F High variation in cost seen between US, EU costs and China, India costs. Moreover, this also depends on technology. Here the chosen values are estimated based on a mix of values available along with employing the learning curve approach used for financial parameters.

12. ELECTROCHEMICAL STORAGE

Brief technology description

With increasing shares of renewable energy in power systems, the role of electricity storage grows in importance. Among all technologies, electrochemical storage (batteries) has experienced notable cost declines in the past years. This is especially true for certain battery types; this catalogue considers the Li-Ion type, which has been used in different grid applications around the world. The potential applications of batteries in electricity systems are very broad, ranging from supporting weak distribution grids, to the provision of bulk energy services or off-grid solutions (Figure 56).

This technology description focuses on batteries for provision of *bulk energy services* and *customer energy management services*, i.e., time-shift over several hours (arbitrage)– for example moving PV generation from day to night hours –, the delivery of peak power capacity, demand-side management, power reliability and quality.

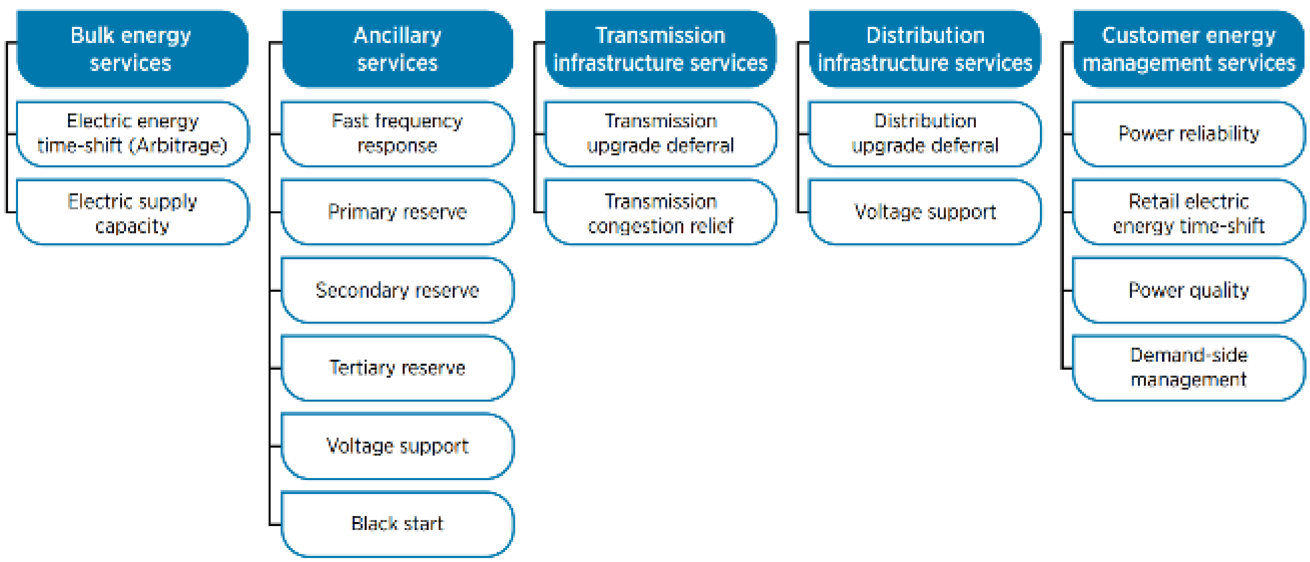

Figure 56: Range of services electricity storage can provide (ref. 41).

Other kinds of electrochemical storage that have reached commercialization today include lead-acid, high temperature sodium sulphur (NaS), sodium nickel chloride and flow battery technologies (vanadium redox flow). Lithium ion batteries (LIB) have however completely dominated the market for grid scale energy storage solutions in the last years and appear to be the dominating battery solution (Figure 57). For this reason, this chapter focuses on LIB.

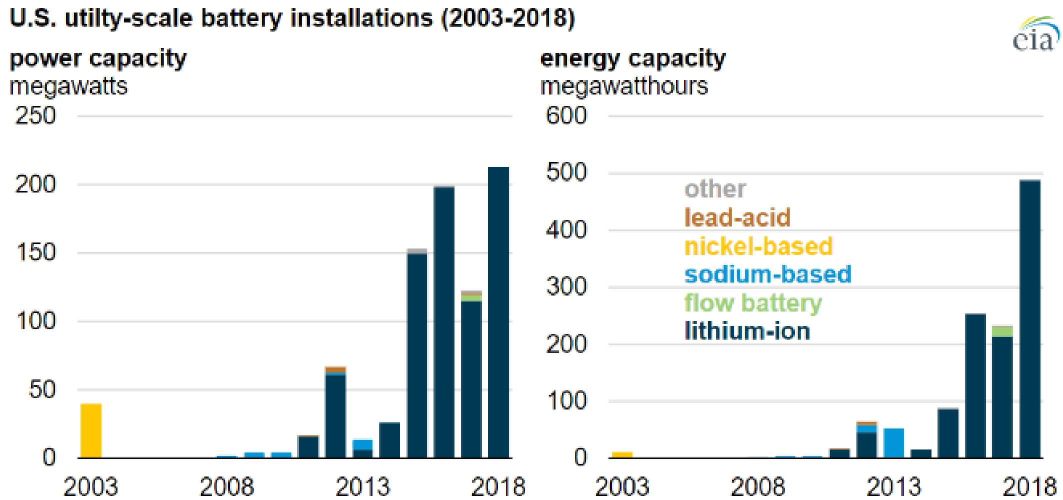

Figure 57: Utility-scale battery installations by type in the US (2003-18) (ref. 47)

A typical LIB installed nowadays has a graphitic anode, a lithium metal oxide cathode and an electrolyte that can be either liquid or in (semi-)solid-state. When liquid, it is composed of lithium salts dissolved in organic carbonates; when solid, lithium salts are embedded into a polymeric matrix. Three major types of Li-Ion batteries installed nowadays for utility-scale storage are reported in Table 18. Li-Ion batteries commonly come in packs of cylindrical cells and can reach energy densities of up to 300 Wh/kg. The unit's footprint can be assumed to be around 5 m^2/MWh.

Table 18: Major LIB types in use for utility-scale storage.

Short name	Name	Anode	Cathode	Energy density Wh/kg	Cycles	Calendar life	Major manufactures
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	120-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam
LFP	Lithum Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony*
LTO	Lithium Titanate	$LiTO_2$	$LiFePO_4$ or Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	70-80	15000-20000	25 years	Leclanche Kokam Altairnano

Electrons flow in the external circuit and Li ions pass through the electrolyte. The charging and discharging of the battery depend on the shuttling mechanism of Li ions between anode and cathode. This process is controlled by an electronic battery management system to optimize cell utilization and degradation, while delivering the desired loading/unloading current. The fast Li-ion transport and the small diffusion distance due to the lamellar architecture of components inside the cell ensure that the response time for LIB is very low (ref. 1). It also has a low self-discharge rate of only 0.1–0.3% per day and good cycle efficiency of up to 97% (ref. 8).

A schematic overview of a battery system and its grid connection can be seen in Figure 58. A Thermal Management System (TMS) controls the temperature in the battery packs to prevent overheating and thermal runaway (the phenomenon is explained in the following). The Energy Management System regulates the energy exchange with the grid. Power electronics convert DC into AC before power is injected into the grid. In some cases (high-voltage grids), a transformer might be required to feed electricity into the grid.

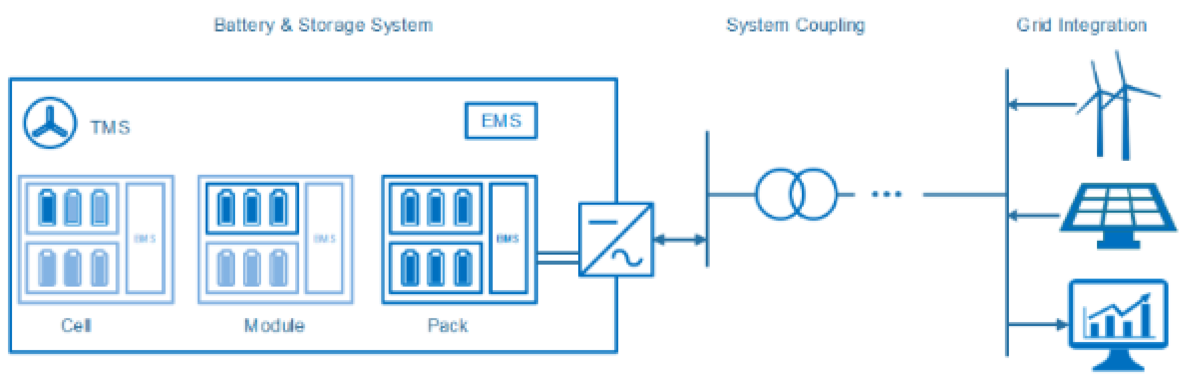

Figure 58: Schematic illustration of a battery storage system and its grid connection.

Charging and discharging rates of LIB are often measured with the C-rate, which is the maximum current the battery can deliver with respect to its volume. For example, if a battery is discharged in 20 minutes, 1 hour and 2 hours then it has C-rates of 3C, C and C/2 respectively. Operations at higher C-rates than specified in the battery pack are possible, but would lead to a faster degradation of the cell materials (ref. 9). Generally, for the same chemistry/construction, a battery going through a 15-minute full discharge will have a lower cycle life (and thereby lifetime) than a similar battery used for a 1 hour full discharge cycle.

LIB do not suffer from the memory effect issue (the effect of batteries gradually losing their maximum energy capacity if they are repeatedly recharged after being only partially discharged) and can be used for variable depths of discharge at short cycles without losing capacity (ref. 11). The relationship between battery volume (in MWh) and loading/unloading capacity (in MW) can be customized based on the system needs and in order to obtain a better business case.

The lifetime of battery energy technologies is better measured by the total number of cycles undergone over the lifetime. Nowadays, a Li-Ion battery typically endures around 10000 full charge/discharge cycles. Batteries generate DC current, which then needs to be converted into AC to be fed into the most interconnected grids. This is achieved through power electronics (inverters).

As mentioned at the beginning of this section, battery energy storage systems (BESS) can have manifold applications and thus can be installed at different voltage levels (Figure 59). BESS architecture is ultimately shared across use types, with minor differences depending on the single applications. In off- and micro-grid contexts (not represented in Figure 59), grid connection costs are reduced totally or partially.

Industry and households can install batteries behind the meter to reshape the own load curve and to integrate distributed generation such as rooftop or industrial PV. The major benefits are related to retail tariff savings, peak tariff reduction, reliability, and quality of supply (ref. 43). Batteries can boost the self-consumption of electricity and back up the local grid by avoiding overload and by deferring new investments and reinforcements. In case of bi-directional flows to/from the grid (prosumption), BESS can increase the power quality of distributed generation and contribute to voltage stability. In developed market settings, these functions might not only reflect requirements enforced by the regulation, but also materialize in remunerated system services.

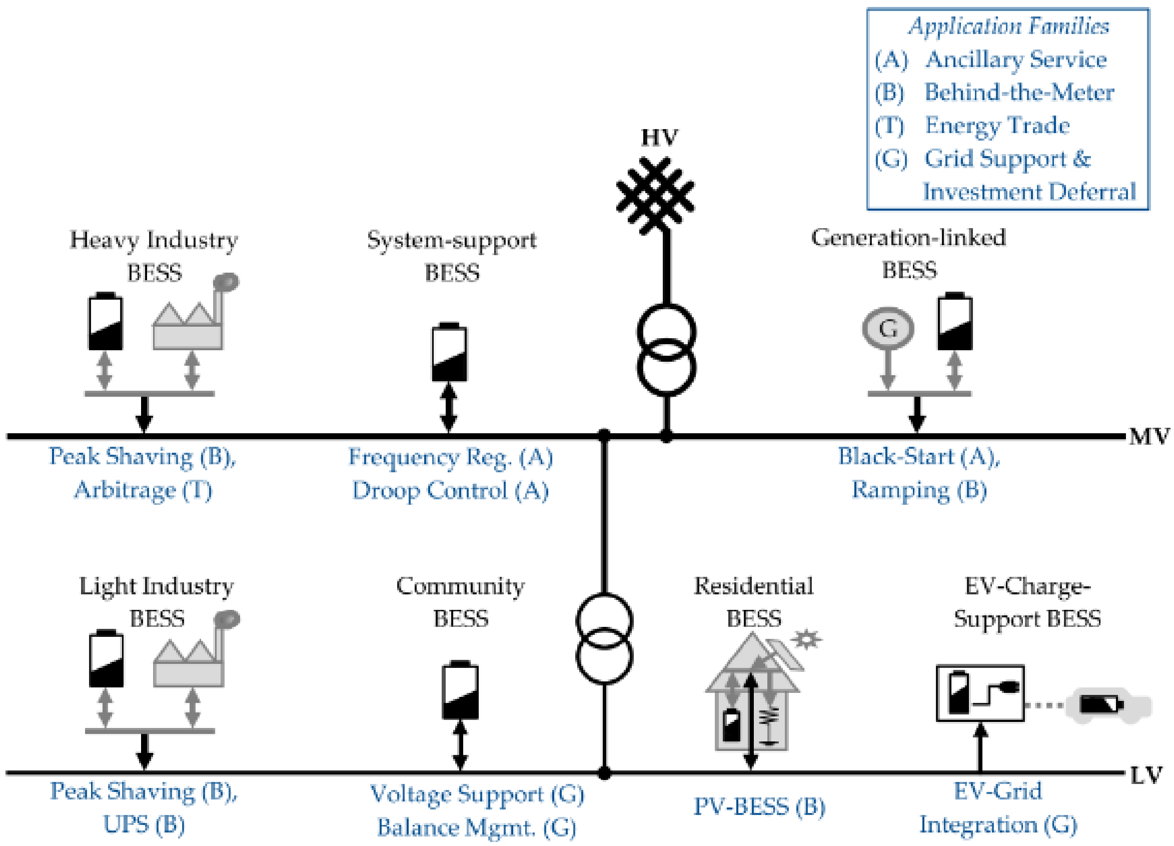

Figure 59: Different uses of battery systems depending on voltage level and application families (ref. 43).

Input
Electricity.

Output
Electricity.

The efficiency of Li-ion battery cells is close to 100%. However, there exist several sources for losses, which can be grouped into operational and stand-by losses. Operational losses are related to the power electronics and to the circuit resistance in the LIB and they increase with the second power of the current flowing in the battery's

external circuit. Stand-by losses are the result of unwanted chemical reactions in the battery (*self-discharge rate*). Self-discharge rates increase with temperature, but can be assumed to be in the order of 0.1% of the energy content per day.
Auxiliaries (thermal management system, energy management system) require energy to run as well, and losses therein must be accounted for as well.

AC-DC conversion and energy demand from the control electronics lead to a grid-to-grid efficiency (AC-AC) of about 90% nowadays. Frequency regulation requires fast short-cycle charge-discharge and reduces round-trip efficiency. Extensive cycling reduces the lifetime of batteries. Overall, the round-trip efficiency can be expressed as a decreasing function of the C-rate, that is how much current is released by the battery.

Typical capacities
For bulk energy services, Li-Ion batteries come in large sizes. Small batteries are in the order of MW/MWh, but can reach several hundreds of MW/MWh. For example, the Hornsdale facility in Australia has 100MW/129MWh capacity/energy components and a further expansion of 50MW/64.5MWh is in the pipeline. For distributed applications, battery size can range from a few kW to hundreds of kW.

For bulk energy services applications (for instance time shifting), several hours of storage might be needed, depending on the system needs. For example, an AES installed LIB facility in San Diego can feed the grid 37.5 MW of power continuously for 4 hours. This tendency will increase in the future with the necessity of moving variable renewable energy generation over long time frames.

Ramping configurations
Li-ion batteries (LIB) installations are very flexible in terms of power/energy capacity and time of discharge. This type of batteries has a response time in the order of milliseconds (determined by the inverter), which makes it suitable for the wide range of applications mentioned before, including power quality.

Advantages/disadvantages
Advantages/disadvantages are considered in relation to other battery technologies.

Advantages:
- Li-ion batteries (LIB) modules do not need particular maintenance and can work in harsh environments, thus operational costs are contained.
- LIB have a relatively high energy and power density.
- Round-trip energy efficiency is remarkably high for LIB among commercially scalable batteries. Other batteries have efficiency 10% lower or more. Some batteries like NiCd/Ni-MH lose energy capacity if not fully discharged. This is called memory effect. LIB do not suffer from memory effect and have low self-discharge.
- The combination of high power and energy density and the very short response time (few milliseconds) enables the usage of LIB in both power intensive applications such as frequency regulation and energy intensive applications like time shifting of dispatch. Li-Ion batteries can therefore benefit from different revenue streams, associated with a set of system services. The lack of memory effect allows short and deep discharging.
- LIB have a relatively long lifetime compared to many other battery types. This strengthens the business case and the financial viability of battery storage systems since it lowers the levelized cost of storage.

Disadvantages:
Li-ion batteries (LIB) have a relatively small number of technical disadvantages, mainly related to electrochemical reactions within the cells.

- Electrode materials are prone to degradation if overcharged and deeply discharged repeatedly. A proper management system can effectively mitigate this problem.
- Continuous cycling lowers the overall lifetime of the battery.
- Li-Ion battery systems need cooling to remove the heat released by the battery modules. The auxiliary consumption needed for cooling can be sizeable depending on the type of application and battery use. Safety issues from thermal runaway are of concern. Thermal runaway arises as a consequence of high temperatures in the battery cells; within milliseconds, the energy content in the battery is emptied out and unacceptably high temperatures are reached. Li-Ion batteries can charge in the 0-45°C temperature range, discharge even at slightly higher temperatures; thermal runaway can start already at 60°C. Overcharging is a cause of thermal runaway.
- The electrolyte has a limited electrochemical stability window. Beyond this limit, a redox reaction takes place between the oxygen released from the cathode and the electrolyte; the battery might catch fire (ref. 21). During a thermal runaway, the high thermal power released from one cell can spread to the adjacent cells, making entire modules unstable.
- Stability of cathode materials in contact with electrolyte is better for phosphate cathodes than oxide cathodes but phosphate-based batteries deliver lower potential. Thermal runaway can be suppressed using inhibitors (ref. 22).
- With LIB demand increasing exponentially every year, the supply of raw materials and incremental costs are the main concerns. Lithium extraction has the potential for geopolitical risks because the world's known resources of easily extractable lithium are largely concentrated in three South American countries: Chile, Bolivia, and Argentina (ref. 23), but the limited availability of cobalt resources remain the biggest concern.
- The self-discharge rate and all the parasitic losses in the system become a significant source of losses at residence times beyond a few days, hence Li-Ion batteries are not advisable for long-term storage.

Environment
Some LIB contain toxic cobalt and nickel oxides as cathode materials and thus need to be meticulously recycled. At present, the market price of component materials like lithium/cobalt is still not high enough for making it economically beneficial. Unlike portable electronics, large installations help enforce recycling regulations.

Lithium resource depletion from fast adoption of LIB in electric vehicles and utility-scale storage is a concern (ref. 24). US-EPA reported that across the battery chemistries, the global warming potential impacts attributable to the LIB production is substantial (including energy used during mining): the literature points at a climate impact ranging from 39 kg $CO2_{eq}$/kWh to 196 kg $CO2_{eq}$/kWh (ref. 46).

Research and development
LIB have been well-known for decades, but their use as utility-scale storage has gained momentum only in recent years. LIB moved from the pioneer phase (category 2) to the commercial phase with a significant development potential (category 3). Therefore, there is still a significantly potential for R&D.

Due to the economic and technological impact, a wide range of government and industry-sponsored research is taking place across the world towards the improvement of LIB at material and system level.

Higher energy density is achievable by discovering new cathode with higher electrochemical potential and anode/cathode materials, which can build in more lithium per unit volume/weight.
Higher electrochemical potential for cathode materials also need to be matched with the electrochemical stability of the electrolyte used. Thus, research in new electrolyte systems is also needed. Electrolytes with better chemical stability also lead to lower chances of thermal runaway. Improved power capacity is obtained if lithium ion movement is faster inside the electrode and the electrolyte materials. In short, cathodes with high electrochemical potential, anodes with low electrochemical potential, cathode/anodes with high lithium capacity, electron/lithium transport, electrolytes with large electrochemical stability window and fast lithium transport are the desirable directions in LIB research.

A nickel-phosphate-based cathode can operate at 5.5 V (compared to 3.7 V of cobalt oxide cathodes), but a complementary electrolyte is not available yet (ref. 25). On the anode side, silicon based anodes can improve upon carbon-based anodes. Stability for long-term operations has however remained an issue (ref. 26). On the electrolyte side, ionic liquids are being researched for safer high potential operations (ref. 27).

In the future, Lithium-Air and Lithium-Sulphur batteries could reach commercialization, but it faces challenges related to humidity, unwanted chemical reactions (production and leaking of polysulphide ions into the electrolyte in the case of Li-S batteries).

Another promising branch of research is linked to Lithium Solid-State batteries (SSBs). SSBs use a solid electrolyte instead of a liquid/gel electrolyte as in today's Li-ion batteries: this would strongly reduce flammability risks and increase the energy density of a battery pack, besides being very stable (ref. 44). The main disadvantages connected to SSBs are the high cost, poor ionic conductivity of the electrolyte, incompatibility between electrolyte and electrodes and the fast growth of lithium dendrites. This eventually leads to a poor cycle performance and a rapid capacity degradation (ref. 45).

Investment cost estimation
In the IEA's 2019 World Energy Outlook, battery installations are forecast to provide 330 GW and 550 GW of system flexibility in 2040 in the Stated Policies and the Sustainable Development Scenarios respectively. India will be one of the leading markets. Given a 2018 cumulative capacity of 8 GW, this returns ~8 capacity doublings in 22 years.

LIB installations for utility operation from major companies like Samsung SDI/TESLA are modular and scalable: costs can be assumed to increase linearly with the storage size. Modular systems that have been used by TESLA to create 80 MWh storage system within 3 months (ref. 29).
Data for the Samsung SDI model is here the main reference for technical parameters; other manufacturers are considered to tune and compare the data.

Due to lack of specific daily discharge loss data, generally accepted information obtained from published journal articles and review papers is used as a standard (ref. 8). Unforeseen outages are very rare and can be considered not to occur, provided that good management is performed.
Samsung SDI also suggests operation between C/2 to 3C rate. A 10C-rate, long lifetime battery (ref. 30) is under development and 20C-60C-rate batteries are being experimented (ref. 31).

Commercial units have nowadays a lifetime of about 10000 cycles (ref. 42). More stable electrode materials (e.g. polyanion cathode and titanate anode) and a better system management are set to boost the asset's lifetime, which is projected to reach 30 years in 2050.

Modular manufacturing and automated installation capabilities can drastically cut down on system setup time to few weeks from current ~3 months, as demonstrated by TESLA.

Round-trip efficiency is already rather high and the improvement in system performance will therefore be minimal in the future. Internal losses depend on advancements in battery chemistry and R&D in cell materials; materials will also affect the performance of power electronics, whose efficiency could improve by some % in the next years due to better-engineered solid-state converters.

The historical and projected prices for Li-Ion batteries are shown in Figure 60, as forecast by Bloomberg. A battery pack is expected to cost 62 USD/kWh in 2030 with the assumption of an 18% learning rate. The IEA's 2019 World Energy Outlook foresees that the total battery system costs will drop to well-below 200 USD/kWh by 2040. Cost reductions are much more significant for the battery pack than for the entire BESS, as power electronics' development is expected to be more moderate. Price drops for the single components of a BESS (battery pack, DC-AC conversion, management systems) are heavily influenced by the potential market applications, which drive R&D efforts and advancements in the manufacturing process.

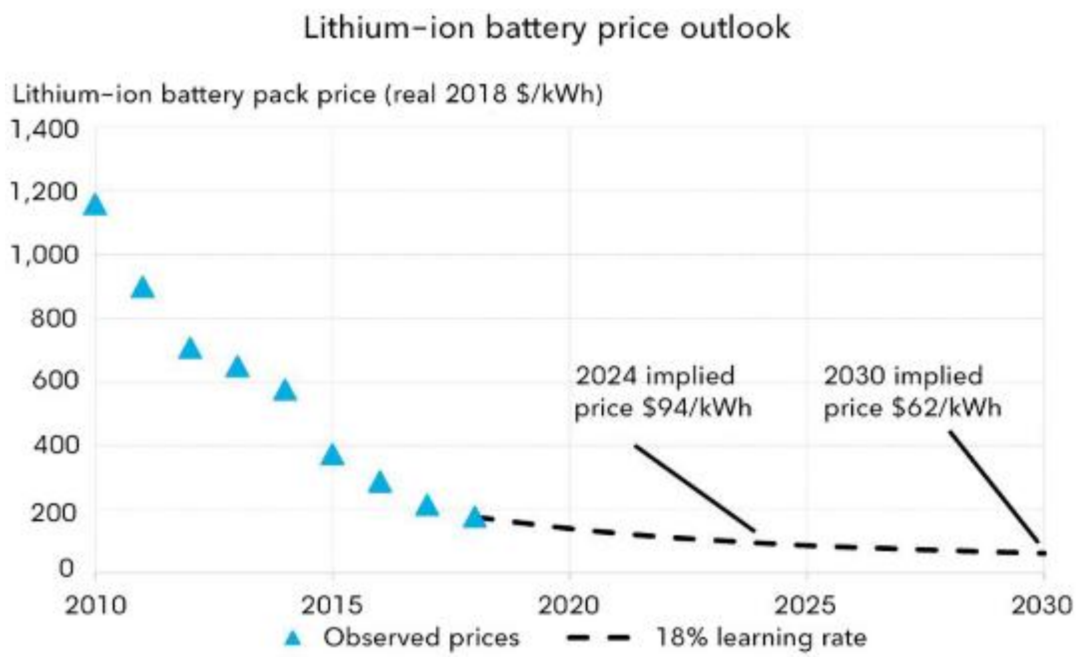

Figure 60: Li-Ion battery pack price projections. Source: Bloomberg NEF.

The price of a small size battery storage such as TESLA's *Powerwall* (13.5kWh/7kW unit, 0.5 C-rate) can be assumed to be around 500 USD/kWh in 2020, which excludes hardware and installation costs. Figures are lower for bigger storage units.

Lazard's Levelised Cost of Storage report estimates O&M costs to lie in a wide range (0.3-5 USD/kWh). These include both fixed and variable O&M. When costs are calculated for the asset's lifetime, O&M can account for

between 1/4 and 1/3 of the Levelised Cost of Storage (ref. 34). Although module costs will decrease, counterbalancing effects from more expensive engineering and further automation would keep installation costs and O&M costs at a similar level or even slightly higher.
Similar to the semiconductor industry, improvements in LIB have been exponential (ref. 35), with price reductions of ~15%/year. Demand from EV and electronic industry have contributed to the accelerated development of the manufacturing industry and of the supply chain. Further improvements came from the R&D knowledge in high-performance materials reaching commercial status. It is assumed that energy density will improve in 2030 by ~30-50% due to R&D efforts put into the battery materials.

Data presented in the data sheet are from specific cases and publicly available sources. Better-negotiated prices are most possibly accessible to project managers. Uncertainty in future development of technology and commercialization affect the accuracy of the suggested numbers for LIB energy storage systems.

	Investment costs [$MUSD_{2019}$/MW]	**2018**	**2020**	**2030**	**2050**
Catalogues	**Technology catalogue for Ethiopia (2021)**		**0.76**	**0.43**	**0.20**
International data	Danish technology catalogue		0.76	0.43	0.20
	NREL ATB		0.86	0.48	0.36
	Lazard	0.63			
Projection	Learning curve – cost trend [%]	-	100%	56%	26%

Note: values for 2-hour storage.

Uncertainty in future data
Development in LIB has been rapid in the last few years and upgrades in manufacturing capacity and technologies have been astounding. This is aided by the explosion of the requirements in the area of EV and portable electronics. Large R&D efforts are accelerating the progress, unlike any other storage technologies. For example, development in 6V capable electrolytes, vanadate cathodes and silicon based anodes can increase the electrochemical potential by 70% and Li-capacity by 3 times – leading to 5-fold increases in the energy density, but these technologies are many years from commercialization. In addition, a polymer gel electrolyte based battery has been developed that has a cycle life of 200,000 at 96% efficiency (ref. 36). Commercialization of such technology can make LIB systems last for centuries.

Examples of current projects

According to the IEA, at the end of 2018 8 GW of battery capacity were installed worldwide, with 3 GW added only in 2018 (the figure includes all types of batteries)[4]. Many energy storage systems provide system support by participating in frequency regulation services. An example of a large such installation is the Hornsdale battery in Australia. Technology providers include TESLA, A123 systems, LG Chem, BYD, Toshiba, Samsung SDI.

- Hornsdale TESLA battery in Australia. 129MWh/100MW, with an expansion in the pipeline of additional 64.5MWh/50MW. The facility provides mainly system support in the frequency regulation market, but also bulk energy services.
- AES/Samsung SDI/Parker Hannifin. 30 MW and 120 MWh (bulk energy service). SDG&E Escondido, San Diego, USA. From 2017.
- Samsung SDI/GE. 30 MW and 20 MWh (black start and frequency regulation). Imperial Irrigation District, El Centro, California, USA. From 2016.
- Toshiba. 40 MW and 40 MWh (bulk energy service for RE). Minamisoma, Fukushima Prefecture, Japan. From 2016 (Figure 61).

Figure 61: Picture of the 40 MW and 40 MWh energy storage system in Fukushima, Japan.

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Technology

Technology	Batteries - Lithium-ion (utility-scale)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	6.0	7.0	8.0					A,B	1,2
Energy/Power ratio (hours)	1.04	2.08	4.16					E	1,2
Discharge time (hours)	1.00	2.00	4.00					E	1,2
Round-trip efficiency (%) AC	91	92	92					C	3,12
Round-trip efficiency (%) DC	95	96	96					C	3,12
Self-discharge rate (%/day)	0.10	0.10	0.10						4
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks per year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	10000	15000	20000					M	5
Technical lifetime (years)	20	25	30					D	
Construction time (years)	0.20	0.20	0.20						
Energy density (Wh/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						6
Financial data									
Nominal investment (MUSD/MWh)	0.578	0.264	0.157	0.455	0.920	0.075	0.398	G	13
- energy component (MUSD/MWh)	0.152	0.062	0.035	0.080	0.215	0.030	0.131		7,8
- power component (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	H	9,10,11
- other project costs (MUSD/MWh)	0.115	0.110	0.105	0.102	0.125	0.023	0.125	N	9,12
Fixed O&M (USD/MWh/year)	621	311	155	500	650	250	350		12
Variable O&M (USD/MWh)	2.30	2.07	1.84	0.45	6.36	0.34	2.84	I	10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.267	0.163	0.086	0.182	0.294	0.052	0.200	B,F	7,8
Output capacity expansion cost (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	B,F	9,10,11

Notes:

A	One unit defined as a 40 feet container including LIB system and excluding power conversion system. Values are taken from Samsung SDI brochures for grid-connected LIBs from 2016 and 2018 [2,14]. Units with C-rates below/above 1 are possible, depending on the system needs and cost of the energy and power rating components. A C-rate of 1 is here assumed for 2020, as it is close to several new installations.
B	Power and energy output can be scaled linearly by utilizing many modules (up to 100MW has been demonstrated). Output capacity expansion can be done reprogramming the management unit without any new battery module.
C	The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90% [21,22].
D	Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C/2 to 3C. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.
E	The discharge time is the amount of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.
F	Since multi-MWh LIB systems are scalar, the energy and outputr capacity expansion costs are here estimated to be equal to the energy and output capacity components plus the "other costs"
G	Power conversion cost is strongly dependent on scalability and application.
H	The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90% [21,22].
I	Cost per MWh of energy discharged from the battery
L	It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and accumulated production. Planned outages is expected to decrease after 2020 due to increased automation.
M	Cycle life specified as the number of cycles at 1C/1C to 80% state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90% DOD) based on chemistry [3]. Thus for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam. Cycle lives are steadily increasing over last few years as reflected in 2020/2030 numbers [4,5,14].
N	Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

Examples for calculation of CAPEX using data sheet:

1. Frequency regulation in 2020: 4C-rate, 2 MWh BESS system. 20 years operation time.

Cost items:
2 MWh "energy component", year 2020
2 MWh "other project costs", year 2020
4C = 0.25-hour discharge time ⇒ 8 MW "power component", year 2020

CAPEX: 2 * (0.152 M$ + 0.115 M$) + 8 * 0.311 M$ = 3.022 M$

2. Energy integration in 2030: ¼C-rate, 16 MWh BESS system. 25 years operation time.

Cost items:
16 MWh "energy component", year 2030
16 MWh "other project costs", year 2030
¼C= 4-hour discharge time ⇒ 4 MW "power component", year 2030

CAPEX: 16 * (0.062 M$ + 0.11 M$) + 4 * 0.184 M$ = 3.488 M$

APPENDIX: FORECASTING THE COST OF ELECTRICITY PRODUCTION TECHNOLOGIES

Historic data shows that the cost of most electricity production technologies have decreased over time. It can be expected that further cost reductions and improvements of performance will also be realized in the future. Such trends are important to consider for future energy planning and therefore need to be taken into account in the technology catalogue.

Three main different approaches to forecasting are often applied:

1. **Engineering bottom-up assessment.** Detailed bottom-up assessment of how technology costs may be reduced through concrete measures, such as new materials, larger-scale fabrication, smarter manufacturing, module production etc. Costs are also influenced by the asset size, i.e. by the development of design parameters over time; for instance, how the design of a wind turbine is expected to evolve over time.
2. **Delphi-survey**. Survey among a very large group of international experts, exploring how they see costs developing and the major drivers for cost reduction.
3. **Learning curves.** Projections are based on historic trends in cost reductions combined with estimates of future deployment of the technology. Learning curves express the idea that each time a unit of a particular technology is produced, some learning accumulates which leads to cheaper production of the next unit of that technology.

Each of the three approaches comes with advantages and disadvantages, which are summarised in Table 19.

Table 19: Advantages and disadvantages of different methodologies for forecasting technology costs

	Advantages	**Disadvantages**
Engineering bottom-up	• Gives a good understanding of underlying cost drivers. • Provides insight to how costs may be reduced.	• Requires information at a very detailed level. • Difficult to obtain objective (non-biased) information from the experts, who possess the best knowledge of a technology. • Potentially very time-consuming.
Delphi-survey	• Input from a large number of experts improves robustness of forecast.	• Costly and time-consuming to carry out surveys. • Challenge to identify relevant and unbiased experts.
Learning curves	• Large number of studies have examined learning rates and documented that learning rates correlations are real. • The over-arching logic of learning rates has proved correct for many technologies and sectors. • Data available to perform learning curves for most important technologies.	• Does not explain why cost reductions take place. • One-factor learning rates are usually adopted, but in practice cost drivers included in the learning curves follow different developments. Multi-factor learning rates potentially make up for this issue, but they are difficult and time-consuming to obtain. • The theory assumes that each technology makes up an independent technology complex, but in practice there may be a significant overlap between different technologies, which makes the interpretation and use of learning curves more complicated. • Forecasting based on learning curves depend on the deployment level of the single technology, which is uncertain in the future.

For the purpose of the present catalogue, the (one-factor) learning curve approach is the most suitable way forward. Firstly, the learning curve correlations are well documented; secondly, the risk of bias is reduced compared to the alternative approaches; thirdly, it does not involve costly and time-consuming surveys.

The results from the learning curves will be compared with projections from international literature.
Learning curve based cost projections are dependent on two key inputs: a projection of the technological deployment and an estimated learning rate. Essentially, this is the only information required to perform cost projections.

Global demand for technologies
To estimate the future demand of each of the technologies we rely on analyses of the future global electricity supply from the International Energy Agency (IEA). Indeed, how the global demand and composition of electricity will develop is associated with a high level of uncertainty related to climate policy ambitions, costs and availability of fossil fuel resources and the development of existing and new electricity generation technologies.

In its latest Energy Technology Perspectives 2020 and World Energy Outlook 2019, the IEA considers two reference global pathways, the Stated Policy scenario and the Sustainable Development scenario, with varying degree of climate policy commitment:

- The **Stated Policies scenario (STEPS)** assesses the evolution of the global energy system on the assumption that government policies that have already been adopted or announced with respect to energy and the environment, including commitments made in the nationally determined contributions under the Paris Agreement, are implemented;
- The **Sustainable Development scenario (SDS)** describes the broad evolution of the energy sector that would be required to reach the key energy-related goals of the United Nations SDGs, including the climate goal of the Paris Agreement (SDG 13), universal access to modern energy by 2030 (SDG 7), and a dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9) (ref. 3).

We use the two IEA scenarios to set a realistic framework for the future technology deployment.

According to IEA's World Energy Outlook 2019 data, it is projected that under the STEPS the electricity demand increases from 371 Mtoe in 2018 to 501 Mtoe in 2040. On the other hand, under the SDS demand for electricity will increase to 423 Mtoe, which is significantly less compared to STEPS. Clearly, an important factor behind the Sustainable Development scenario is a reduction in the rate of increase in demand, as a consequence of energy efficiency measures and reduced energy intensity. Moreover, looking at the projection by energy source, there is a slight reduction in the use of coal and oil under STEPS, whereas the reduction in usage of coal, oil and natural gas is much more significant in the Sustainable Development scenario. This development is further represented in the electricity capacity projections from 2018 to 2040. The IEA scenarios provide data only up to 2040. For the projections to be in line with this catalogue and provide information up to 2050, the data is calculated through forecasting of capacity added and retired from 2040 to 2050. Therefore, the projections between 2040-2050 are more uncertain.

The final projections of electricity generation capacity for 2018 to 2020 as per world energy outlook 2019 data and forecasting done are represented in Figure 62. As can be seen, for SDS, the projections estimate a significant increase in renewables like solar and wind, and a reduced dependency on fossil fuels in order to meet the sustainable development goals. It can also be noted that the projected installed capacity in the SDS scenario is higher compared to STEPS. This is due to the fact that technologies like wind and solar have lower capacity factors and therefore more capacity is needed to supply the same demand.

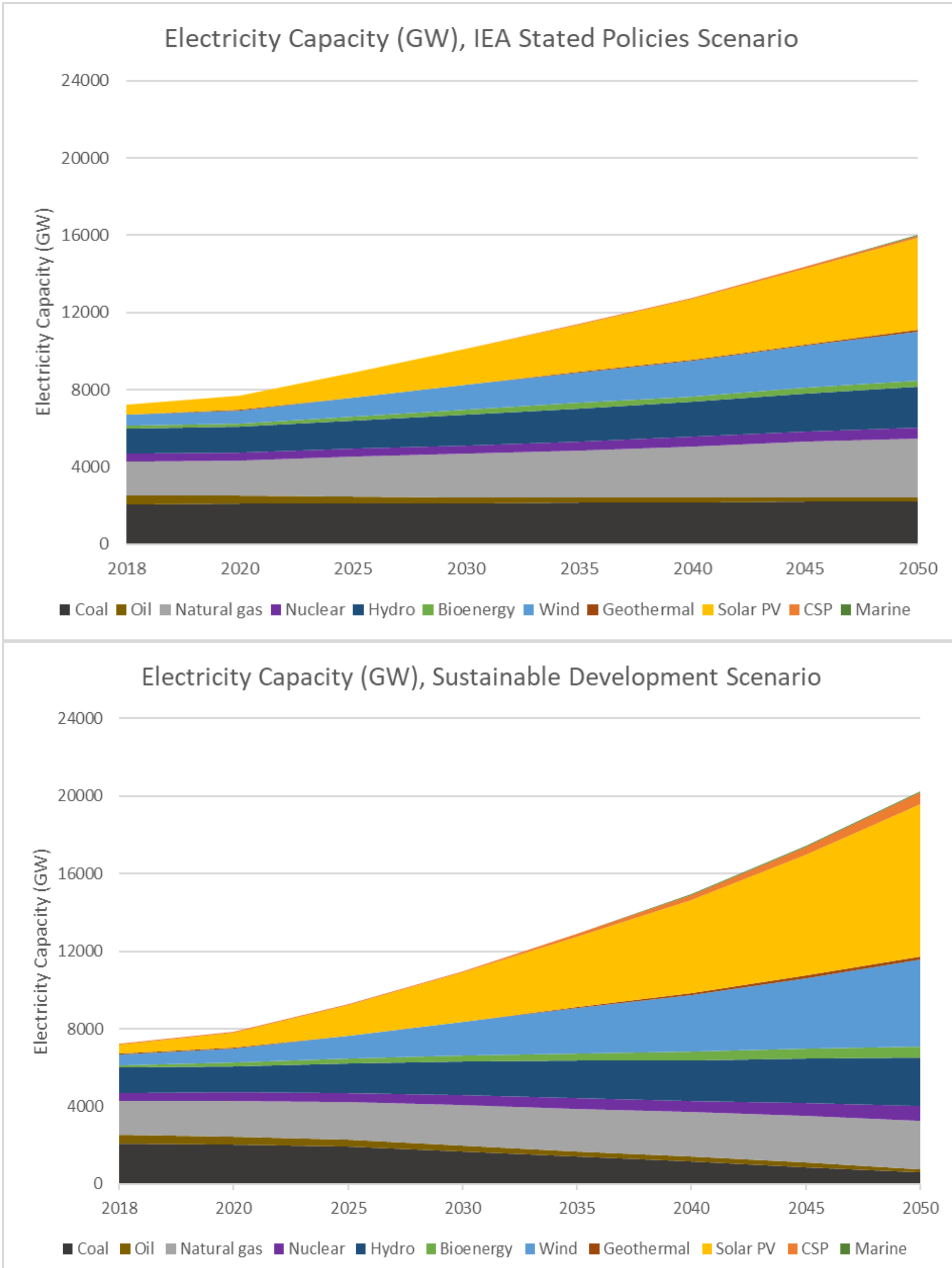

Figure 62: Electricity Capacity (GW) in the IEA's stated policies and sustainable development scenarios (ref. 3)

Table 20 and Table 21 show the development of accumulated capacities of different electricity generation technologies toward 2050, using 2020 as the starting point (=1). The accumulated figures represent total installations, taking into consideration the need for replacement of progressively decommissioned power plants over the period. Under STEPS it is seen that the only fossil fuel significantly reduced is oil. This implies that if on-going policies are followed, globally coal and natural gas will still make up a major share of the energy supply. However, under the SDS the projected increase of electricity capacity of wind is over three-fold, solar is over four-fold and CSP and marine technologies play a significantly greater role.

Table 20: Accumulated generation capacities relative to 2020, in the STEPS scenario.

Accumulated generation capacity relative to 2020 (=1)	**2030**	**2040**	**2050**
Coal	1.12	1.28	1.41
Oil	1.06	1.12	1.18
Natural gas	1.33	1.65	1.96
Nuclear	1.20	1.46	1.69
Hydro	1.22	1.43	1.66
Bioenergy	1.52	2.13	2.69
Wind	2.07	3.40	4.62
Geothermal	1.87	3.51	4.77
Solar PV	2.63	4.69	6.49
CSP	3.01	8.05	11.49
Marine	3.91	14.89	21.19

Table 21: Accumulated generation capacities relative to 2020, in the SDS scenario.

Accumulated generation capacity relative to 2020 (=1)	**2030**	**2040**	**2050**
Coal	1.06	1.07	1.11
Oil	1.06	1.12	1.18
Natural gas	1.22	1.44	1.69
Nuclear	1.25	1.58	1.92
Hydro	1.31	1.60	1.95
Bioenergy	1.81	2.76	3.92
Wind	2.50	4.55	6.95
Geothermal	2.52	5.40	8.24
Solar PV	3.23	6.38	9.84
CSP	3.70	19.88	43.54
Marine	4.72	18.77	30.95

Learning rates
Learning rates typically vary between 5 and 25%. In 2015, Rubin et. al, published "A review of learning rates for electricity supply technologies", which provides a comprehensive and up to date overview of learning rates for a range of relevant technologies (ref. 4):

Table 22: Learning rates for different technologies (ref. 4)

Technology	**Mean learning rate**	**Range of studies**
Coal	8.3%	5.6 to 12%
Natural gas CC	14%	-11 to 34%
Natural gas, gas turbine	15%	10 to 22%
Nuclear	-	Negative to 6%
Wind, onshore	12%	-11 to 32%
Wind, offshore	12%	5 to 19%
Solar PV (modules)	23%	10 to 47%
Biomass power	11%	0 to 24%
Geothermal	-	-
Hydroelectric	1.4%	1.4% (one study)

The authors of the review emphasize that "methods, data, and assumptions adopted by researchers to characterize historical learning rates of power plant technologies vary widely, resulting in high variability across studies. Nor are historical trends a guarantee of future behaviour, especially when future conditions may differ significantly from those of the past.".

Still, the study gives an indication of the level of learning rates, which may be expected. A common level for many technologies seems to be 10-15%. PV shows a higher level, whereas nuclear power and coal are in the lower end. The low learning rates of nuclear and coal power may be a result of increasing external requirements, in the shape of higher safety standards for nuclear power and emission norms for coal power, adding to investment costs.

Considering the uncertainties related to the estimation of learning rates a default learning rate of 12.5% is applied for all technologies except solar PV modules, where a learning rate of 20% is deemed to be more probable in view of the high historic rates. It is important to note that this is considering a 25% rate to the PV module and inverter costs, while for the rest of the components and costs for solar PV, the 12.5% learning rate is applied. When the abovementioned learning rates are combined with the future deployment of the technologies projected in the IEA scenarios, an estimate of the cost development over time can be deduced.

Table 23: Estimated technology cost in the IEA's STEPS and SDS scenarios from 2030 to 2050 relative to 2020 (ref. 3).

Technology cost compared to 2020 (2020 = 100%)		**STEPS**			**SDS**			**Average of STEPS and SDS**		
Technology	**Learning rate**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Coal	12.50%	98%	95%	94%	99%	99%	98%	98%	97%	96%
Oil	12.50%	99%	98%	97%	99%	98%	97%	99%	98%	97%
Natural gas	12.50%	95%	91%	88%	96%	93%	90%	95%	92%	89%
Nuclear	12.50%	96%	93%	90%	96%	92%	88%	96%	92%	89%
Hydro	12.50%	96%	93%	91%	95%	91%	88%	96%	92%	89%
Bioenergy	12.50%	92%	86%	83%	89%	82%	77%	91%	84%	80%
Wind	12.50%	87%	79%	74%	84%	75%	69%	85%	77%	72%
Geothermal	12.50%	89%	79%	74%	84%	72%	67%	86%	75%	70%
Solar PV[5]	20%	73%	61%	55%	69%	55%	48%	71%	58%	51%
CSP	12.50%	81%	67%	62%	78%	56%	48%	79%	62%	55%
Marine	12.50%	77%	59%	56%	74%	57%	52%	76%	58%	54%

For all thermal technologies, i.e. oil, coal natural gas, nuclear and biomass power, moderate cost decreases are projected, up to around 20% by 2050. The main reason for this is the extensive historic deployment of the thermal technologies, which means that their relative growth is moderate. Solar PV, CSP and marine technologies are expected to see the strongest cost reductions. For solar PV, this is also due to the higher anticipated learning rate (20%) compared to the other technologies (12.5%). In this respect, it should be mentioned that the projection for CSP and particularly marine technologies is associated with particularly high uncertainty, due to the limited application of these power generation technologies today.

Wind is already widely deployed, and hence, the projected cost development is also moderate, a reduction of approximately 28% is projected by 2050. It should be mentioned that almost all the learning curve studies for wind power, referenced by Rubin et al. focus only on the development of the capital cost of the wind turbines ($ per MW). At the same time, focus from manufacturers have been dedicated to increasing the capacity of wind turbines (higher full load hours per MW) and therefore the effective cost reduction expressed as levelized cost of electricity generation, is likely to be higher. This trend is likely to prevail in the future.

Some technologies have several common core components. For example, coal and biomass fired power plants apply a boiler and steam turbine. This implies that learning effects from the deployment of example biomass fired power plants will have a spill-over effect on coal-fired power plants and vice versa.

[5] For solar PV, the learning rate is 25% for modules, but the rest of the costs are still considered at 12.5%. Therefore, to accommodate this, the rate here I set to 20%.

Global and regional learning

The learning effects found in this review express a global view on technology learning. Considering that the majority of technology providers today are global players this seems to be a reasonable assumption. Therefore, cost reductions generated in one part of the world will easily spread to the other regions.

Still, in a 2020 perspective local prices of some technologies may be higher (or in some cases lower) than international reference values because local expertise is limited. However, as local know-how is built up and technologies are adapted to the local context within the next decade, it is reasonable to assume that cost will approach the international level.

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